2022 IRP

TECHNICAL APPENDIX

VOLUME 3

TRANSMISSION PLAN

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FOREWORD

The documents presented in this volume of the IRP Technical Appendix represent a snapshot of Georgia Power Company's transmission and distribution (T&D) plan, as of December 2021. 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.

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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, 2020, Georgia Power's transmission system consisted of 46kV (2,756 miles), 69kV (105 miles), 115kV (5,831 miles), 230kV (2,482 miles), and 500kV (1,154 miles) lines totaling approximately 12,328 miles. This transmission system, along with other ITS transmission facilities, connected approximately 14,413 MW of GPC-owned, installed generating capacity. The total GPC residential, commercial, and industrial peak demand served in 2021 was approximately 16,214 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, and Mississippi. In addition, the SCES is a member of the SERC Reliability Corporation (SERC), one of six regional entities of the North American Electric Reliability Corporation (NERC).

Transmission Planning-East (TP-E) of Southern Company Services (SCS) and Power Delivery Planning and Policy of GPC, are responsible for planning the transmission system for GPC. TP-E develops a planning model of the transmission system for the current year and 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, Dominion Energy South Carolina (DESC), 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
4. Block wholesale contracts

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 necessary to comply with NERC Reliability Standards.
3. Minimize costs associated with the transmission system expansion, considering the impact to system reliability and system operations.
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. Minimize 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.

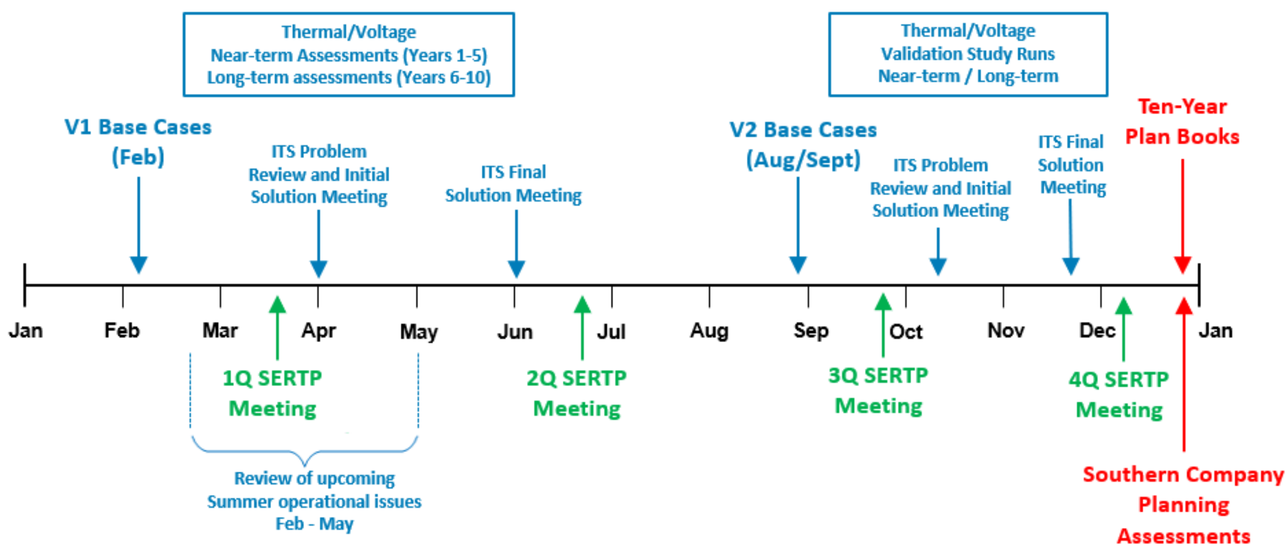
LOAD FLOW

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 2021 Base Case is a load flow model for the summer coincident peak hour of 2021. It includes all transmission projects that have been or will be completed by May 1, 2021. 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 constraints. 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 switching stations, construction of new lines, 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 various 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 identify 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 ITS 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 ITS Participants for review and error checking. ITS Participants suggest changes or corrections that need to be made before the final base cases (Versions 1 and 2) are used for screening for thermal and voltage constraints.

    c. After Version 1 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 2 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 ITS Participant meet at the Transmission Planning Working Group (TPWG) meeting. At this meeting:

   a. Each ITS 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 ITS Participant requires work to be done in another ITS 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 ITS 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 ITS 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 ITS 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 ITS 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 SCS Transmission Planning, 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 fully 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. For issues in the last five years of the planning horizon, viable projects are identified but not fully scoped, estimated and budgeted unless long lead-time items such as right-of-way acquisition are included.

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 & Policy 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, shunt reactor or synchronous condenser, 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. Examples:

- Static Var Systems (SVS) or synchronous condensers to regulate voltage and provide electrical stability to the surrounding network instead of pursuing transmission upgrade projects.
- Static series reactors to shift some of the power flow on overloaded facilities to nearby facilities with more available capacity.
- Active current-limiting devices that can change line impedance manually or automatically depending on real-time circuit loading.
- Distributed Energy Resources (DERs), including battery storage and small generators, that can offset load increases. For thermal overloads, such resources are most likely to be suitable in situations where load is served radially, either normally or as a result of a contingency. In these situations, each MW from a generator or battery provides one MW of circuit loading relief, and the DER can be located anywhere downstream of the overload. A DER might then be selected as a permanent or temporary alternative to constructing a new line and/or substation, or upgrading existing facilities, to serve the additional load. For overloads of networked facilities, a DER solution is typically not practical due to the larger capacity that is usually required and the limited connection points where it can be located to effectively relieve the overload without adversely affecting downstream facilities, which are often loaded to a level close to their ratings.

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)

<u>ELECTRICAL FEASIBILITY</u>

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, environmental permitting and substation 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 Estimating 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, and viable projects are identified to address any constraints, the data and assumptions used to construct the last five years of the system model are typically too fluid to take through the approval and budgeting process. Certain long lead-time projects, typically new lines requiring extensive right-of-way acquisition, are exceptions to this. 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 Expenditures (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; however customer choice projects over $1M or other projects over $5M must also be approved by the T&D Council.

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. Transmission Planning currently uses PSS/E Version 34.

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.

<u>EMTP - Electromagnetic Transients Program</u>

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.

<u>Economic Dispatch Program</u>

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 (lambda). 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.

<u>REVREQ - Revenue Requirements Program</u>

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 SINCAL - Power System Simulator Siemens Network Calculation Tool

The PSS SINCAL 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. SINCAL’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

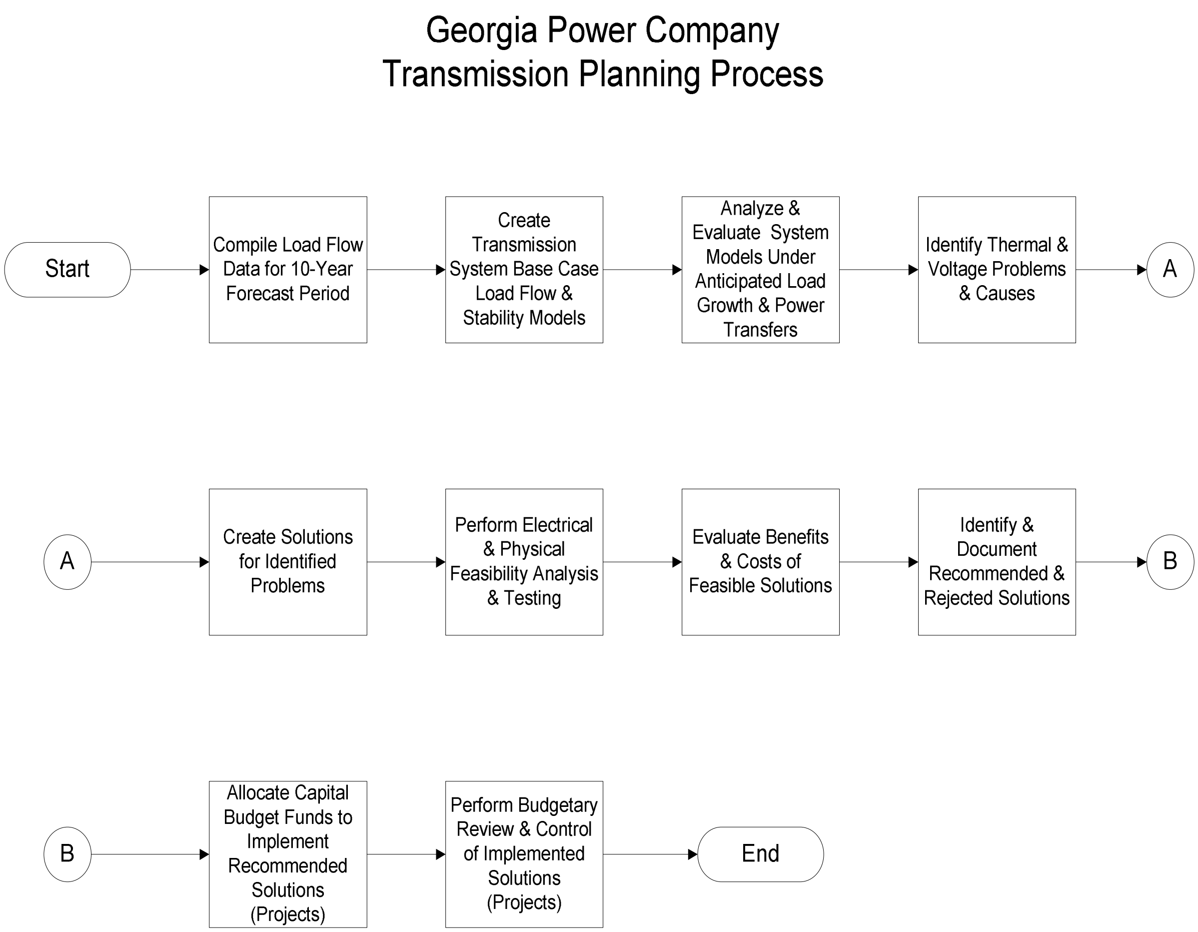
PPPD is an EPRI developed program. PPPD can be used to validate and fine tune/estimate models and their parameters for synchronous generating units and their control using the data obtained through either staged field testing of the generating units or on-line disturbance data.

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



[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, and Mississippi. 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: 12/02/2021

ASSOCIATED NERC RELIABILIT Y STANDARD(S):
TPL-001-5 (referred to as TPL-001 in this document)

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 document 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 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 long-term firm delivery from their resource choices to their customer loads under a wide-range of system conditions. Securing long-term firm 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

The Distribution Service Provider (DSPs) 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. DSPs 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 DSPs 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. DSPs 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), DSPs may provide native load reservations for future resources as inputs into the transmission planning process. However, to receive firm service, DSPs 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 if 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:

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-032 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 SBAA, including the ITS Participants' facilities, in a database which is typically used to build 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-032-1. The planning base case models contain the most recent as-built system data plus the most recent projected Corrective Action Plan (CAP) and therefore represent the projected system conditions. Transmission Planning base case models are developed utilizing input from modeling processes of applicable entities including but not limited to the Eastern Interconnection Reliability Assessment Group (ERAG), SERC Long-Term Working Group (LTWG), and Florida Reliability Coordinating Council (FRCC).

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 the system in future years.

The system dynamic models for the Southeastern 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. New planned Facilities and changes to existing Facilities
> 1.1.3. Real and reactive Load forecasts
> 1.1.4. Known commitments for Firm Transmission Service and Interchange
> 1.1.5. Resources (supply or demand side) required for Load

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 The Transmission system topology, including projects in the most recent CAP and other expected Transmission improvements for the Near-Term and Long-Term Transmission Planning Horizons. The current forecasts of generation expansion or resource plans are provided by all Distribution Service Provider (DSP) and Network Integration Transmission Service (NITS) customers.

1.1.3 Real load forecast is obtained from the DSP'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.

1.1.4 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 LTWG. Additional modeling updates obtained from neighboring utilities and/or other modeling coordination processes may also be used.

1.1.5 Generation resource assumptions are based on the latest information provided by the DSPs 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. The TSA amounts are coordinated with neighboring utilities through SERC's LTWG and other modelling coordination processes.

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 summarize study results validating the CAP. For Southern Company, the consolidated steady state analysis Planning Assessment consolidates the CAPs of Southern's three OPCos and the ITS participants. 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 appropriate 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 or other mitigation actions until projects have transitioned from planning to a construction stage. These reassessments also investigate potential need for additional mitigating actions 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 motoring[1]), 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.

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. 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, DSPs 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.

[1] 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.

> Qualifying studies need to include the following conditions:
>
> 2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

TP/PC Technical Rationale (Known Outages): In the SBAA, most outages for system additions and maintenance are taken in the Spring and Fall times of the year due to the lower load levels and availability of generation for redispatch. Each outage goes through a rigorous review and scheduling process to ensure that system reliability is maintained. The outages of more concern for inclusion in steady-state planning assessments for the SBAA in the Near-Term Planning Horizon are those that are expected to occur during the Summer and Winter peak seasons when system load is much higher and fewer resources exist for use in generation redispatch. It is outages that occur during these higher load level periods that need to be evaluated for inclusion in system steady-state assessments per the standard. To accomplish this, outages which are known to be required during these periods will be reviewed for inclusion in the Near-Term Planning Horizon system analysis.

For the SBAA, known outages are defined as:

1. An outage that is planned and scheduled in the Near-Term Planning Horizon, including those with some level of schedule uncertainty.
2. An outage that is the result of equipment that has been damaged and where the equipment is projected to be out of service for an extended period of time.

Within the SBAA, outage coordination is a continuous process with outages being evaluated and added to the known SBAA outages throughout the year. A request for a list of outages that are known, at the time of the request, will be sent at least annually to the SCS Bulk Power Operations Department. The list received from the SCS Bulk Power Operations Department will be the outages considered for inclusion in Near-Term Planning Horizon steady-state assessment. This list can be augmented with outages from TOs which meet the criteria, but which were not included in the official outage list obtained from the Bulk Power Operations Department if the outages are determined to have a significant reliabitility impact. Once the list is received from SCS Bulk Power Operations, each PC in the SBAA will evaluate the outages in their area to determine if, based on timing, location, and duration the outage should be included in cases or should be included in in the assessment. In the SBAA, duration will never be the sole reason for exclusion of an outage for inclusion in the model. The review will include determining what Facilities will be taken out of service in the model especially when multiple sections of a breaker-to-breaker line are included. Once the outages have been reviewed and selected for inclusion, a review with the Reliability Coordinator (RC) and/or their staff will take place to ensure the RC is in agreement that the most limiting system conditions will be included in steady-state planning assessments.

Assessments are performed for known outages on peak and off-peak planning models for the P0 and P1 (known outage plus additional single contingency) planning events as described in R3.4 with contingencies evaluated per R3.3.

> 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 assessed. The analysis 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 is reviewed annually by the ITS Spare Equipment Working Group 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" provided in Appendix A.

> 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, Part2.6. 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.

> 2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

TP/PC Technical Rationale (Known Outages): In the SBAA, most outages for system additions and maintenance are taken in the Spring and Fall times of the year due to the lower load levels and availability of generation for redispatch. Each outage goes through a rigorous review and scheduling process to ensure that system reliability is maintained. The outages of more concern for inclusion in stability planning assessments for the SBAA in the Near-Term Planning Horizon are those that are expected to occur during the Summer and Winter peak seasons when system load is much higher and fewer resources exist for use in generation redispatch or during Spring and Fall seasons at light load levels. It is outages that occur during these load levels that need to be evaluated for inclusion in system stability assessments per the standard. To accomplish this, outages which are known to be required during these periods will be reviewed for inclusion in the Near-Term Planning Horizon system stability analysis.

For the SBAA, known outages are defined as:

1. An outage that is planned and scheduled in the Near-Term Planning Horizon, including those with some level of schedule uncertainty.
2. An outage that is the result of equipment that has been damaged and where the equipment is projected to be out of service for an extended period of time.

Within the SBAA, outage coordination is a continuous process with outages being evaluated and added to the known SBAA outages throughout the year. A request for a list of outages that are known, at the time of the request, will be sent at least annually to the SCS Bulk Power Operations Department. The list received from the SCS Bulk Power Operations Department will be the outages considered for inclusion in Near-Term Planning Horizon stability assessment. This list can be augmented with outages from TOs which meet the criteria, but which were not included in the official outage list obtained from the Bulk Power Operations Department if the outages are determined to have a significant reliabitility impact. Once the list is received from SCS Bulk Power Operations, each PC in the SBAA will evaluate the outages in their area to determine if based on timing, location, and duration the outage should be included in in the assessment. In the SBAA, duration will never be the sole reason for exclusion of an outage for inclusion in the model. The review will include determining what Facilities will be taken out of service in the model especially when multiple sections of a breaker-to-breaker line are included. Once the outages have been reviewed and selected for inclusion, a review with the Reliability Coordinator (RC) and/or their staff will take place to ensure the RC is in agreement that the most limiting system conditions will be included in stability planning assessments.

Assessments are performed for known outages on peak and off-peak planning models for the P0 and P1 (known outage plus additional single contingency) planning events as described in R3.4 with contingencies evaluated per R3.3.

> 2.4.5. 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The Transmission equipment sparing strategy is reviewed annually by the ITS Spare Equipment Working Group 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.

- See Section 2.1.5 above for details on how the spare equipment list is obtained.

> 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, Part2.6 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” provided in Appendix A.

> 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, stability limits, and system improvements. The recommendations made are included in the CAP.

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 Remedial Action Schemes
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance constraints.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance constraints.
- 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 provided to Transmission Operations (including the RC) for review at least annually 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 DSPs 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 meet 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 provided to Transmission Operations (including the RC) annually for review. 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 constraints. 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” provided in Appendix A.

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 SBAA 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 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.

<u>Transmission lines</u>
For 230kV and above, contingency case line loading results are screened against 150% of the Winter Rate A Facility Rating and where exceeded are evaluated against actual relay setting.

For all transmission lines below 230kV, contingency case line loading results are screened against 125% of the Winter Rate A Facility Rating and where exceeded are evaluated against actual relay setting.

<u>Autotransformers</u>
500/230kV, 230/161kV or 230/115kV 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 acceptable thermal loading criteria:

- 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 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 comprehensive “more severe planning event 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 system performance criteria. 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 units[2] 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 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

[2] For combined cycle units individual unit contingencies include the full CT + ST outage.

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 though 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 – The non-redundant relay schemes are evaluated by simulating the event as described by the Protection and Controls Department as a result of CAPE simulation results.

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. The standard allows for system operators to 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 the loss of the first Transmission element, system adjustment may include Transmission switching and allowable generation dispatch adjustments in preparation for an additional P6 contingency event the outage of the next (second) element.

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 goal of expected system re-dispatch, when generation is lost due to contingency, is to maintain the load/generation balance and is not made to favorably prepare the system for a subsequent event. Therefore, this re-dispatch is not classified as an intentional system adjustment.
- Other adjustments which occur in a simulation to model automatic equipment operation – 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 constraint. 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 options allowed by the Standard. 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 should be evaluated assuming that the system adjustment has 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 Remedial Action Scheme 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 or trip on voltage relay protection. If a unit is determined to pull out of synchronism or trip on voltage relay protection, 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. 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.

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.

4.3.1 – In all stability simulations remove all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. Where high-speed reclosing is used, unsuccessful reclosing will be simulated. Successful high-speed reclosing is typically not simulated as, compared to unsuccessful high-speed reclosing, successful high-speed reclosing is expected to result in the same or less adverse results.

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

4.3.2 - 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

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 may 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 angular 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, used in stability studies is dispatching down generation to maintain stability for the next contingency. The adjustments are given to Operations as stability limits. 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. Note that such System Adjustments to dispatch down generation for stability studies as described above should not be considered for nuclear units.

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.

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 stability limits). 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.

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 performance voltage ranges for the pre-Contingency and post-Contingency bus voltage for TPL-001 analysis. These voltage ranges are typically used for all planning analyses as a starting point but select studies may utilize tighter limits based on the study purpose.

Table 5.1 A

Planning Event		500 kV	230 kV through 100 kV
		Acceptable Voltage Range	Acceptable Voltage Range
P0 - No Contingency	Generator High-side Bus(1)	0.98 - 1.075(2)	0.95 - 1.05(2)
	Switching Station	0.98 - 1.075	0.95 - 1.05
	Load Serving Bus	0.98 - 1.075	0.95 - 1.05
P1 - P2 Single Contingency	Generator High-side Bus(1)	0.98 - 1.075(2)	0.95 - 1.05(2)
	Switching Station	0.97 - 1.075	0.92 - 1.05
	Load Serving Bus(3)	0.97 - 1.075	0.92 - 1.05
P3 - Multiple Contingency	Generator High-side Bus(1)	0.98 - 1.075(2)	0.95 - 1.05(2)
	Switching Station	0.97 - 1.075	0.90 - 1.05
	Load Serving Bus(3)	0.97 - 1.075	0.90 - 1.05
P4 - P5 Multiple Contingency	Generator High-side Bus(1)	0.98 - 1.075(2)	0.95 - 1.05(2)
	Switching Station	0.97 - 1.075	0.90 - 1.05

	Load Serving Bus(3)	0.97 - 1.075	0.90 - 1.05
P6 - P7 Multiple Contingency	Generator High-side Bus(1)	0.98 - 1.075(2)	0.95 - 1.05(2)
	Switching Station	0.97 - 1.075	0.90 - 1.05
	Load Serving Bus(3)	0.97 - 1.075	0.90 - 1.05

Footnotes:

1) 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.
    e. Exceptions may be considered for plants above 75 MVA that cannot hold voltage schedule for some standard planning contingencies, if:
        i. Voltage stability margins are above the minimum 5% threshold and
        ii. Power flow analysis indicates that there are no other voltage constraints at any load serving buses
2) See discussion of Generator terminal bus voltage limits in Section 5.3.
3) Stations which become radial as a result of the planning event are screened against the same criteria as the post-Contingency networked buses, but if bus voltage remains above the P0 minimum the voltage is acceptable.

5.2 Voltage Deviation

Voltage deviation is defined as the voltage difference between pre-contingency/pre-fault and post-contingency/post-fault voltages.

- In the steady state, post-contingency voltage deviations must not result in bus voltages outside the Acceptable Voltage Range listed in Table 5.1A.
- When capacitor banks are manually switched in or out, the step change in voltage should be no greater than +/- 2.5% under N-0 conditions, and no greater than +/- 6% under Contingency.
- Voltage deviations in transient conditions represent impacts to System stability and/or power quality.
    - Power quality limits are documented in ITS Operating Procedure 26 (ITS Voltage Fluctuation Guideline). Impacts to power quality are typically limited to distribution systems and not applicable to TPL-001 Requirement R5.
    - As it relates to System stability, voltage deviation assessments fall within the larger voltage-related criteria documented in sections 5.6 and 6.

5.3 Generator Terminal 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.

5.4 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.

5.5 Extreme Event Steady State Transmission Voltage Level Ranges and Deviation

Extreme event contingencies are screened against the same criteria as the post-Contingency P6 and P7 events. These events are then further evaluated to ensure that no steady state voltage collapse is identified.

5.6 Transient (dynamic) voltage response

Summer Peak Demand load levels: For normally-cleared faults (P1-P3), voltages must recover above 80% of the nominal 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 nominal 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 nominal voltage for more than 40 cycles. This only applies to Off-Peak load levels with a standard load model (ZIP) 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 due to line overloads. If the planning event (or extreme event) results in lines loaded above their relay loadability limits, or voltage instability as indicated by non-convergent study cases, then additional 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. Any post-Contingency loading which exceeds the relay loadability limit of the Facility is simulated as opening.

2. The resulting post-Contingency case is evaluated to determine if any additional relay loadability limits have been exceeded. If so, these lines are also opened as a result of relay operation. This step will be repeated until no lines open due to relay loadability or ten (10) lines have been opened without resolving thermal limitations.

3. Once all facilities are within their relay loadability limits, PSS/E's remedial action activity is initiated to shed load and adjust capacitors to resolve line overloads (based on Summer Rate B) or voltages below 0.90 per unit after a steady state power flow solution is achieved. 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 five facilities are eventually simulated as opening successively following the initiating event and prior to a post-Contingency case solution, 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 (not including the faulted element) 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, SCS 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).

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

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

GTC performs the PC/TP responsibilities for all TPL-001 requirements. This is coordinated with SCS PC/TP responsibilities through joint ITS study efforts and a separate planning services agreement between GTC and GPC.

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.

Appendix 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-032[i].

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 constraints. 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.

SCS 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 SCST 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/TCs 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
5.0	December 11, 2020	Minor modifications to clarify requirements for TPL-001-4
6.0	December 8, 2021	Modifications to clarify requirements and methodology due to TPL-001-5

I.T.S PLANNING PROCEDURE NO. 9

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

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

DocuSigned by:
Jeremy Talley 12/9/2021
B4BC9FCD631A40A...
Jeremy Talley – DU / Date

DocuSigned by:
William B. McDaniel 12/8/2021
F6896EB81B4043E...
Will McDaniel – DU / Date

DocuSigned by:
Chase Battaglio 12/8/2021
DC29DD094421447...
Chase Battaglio – GPC / Date

DocuSigned by:
J. Chris Weaver 12/8/2021
B08FE937613F48C...
Chris Weaver – DU / Date

DocuSigned by:
Joe Sowell 12/9/2021
BC88021324A346D...
Joe Sowell – GTC / Date

DocuSigned by:
Bob Casey 12/8/2021
B4CBE3F1DEC64AC...
Bob Casey – GTC / Date

DocuSigned by:
Gary McAdam 12/8/2021
E7340B640C4B4BE...
Gary McAdam – MEAG / Date

DocuSigned by:
Robert B Boucher 12/9/2021
BEB20F3E6DA14C4...
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

[signature] for Randy Kirkus 4/12/00
Randy W. Kirkus – GPC / Date

Seth W. Brown 4-12-00
Seth W. Brown – GTC / Date

[signature] for Greg 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]

2021 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 2021:

1. 2021 Summer Peak Load Cases

A set of 2021 summer base cases was created using a modified dispatch of the generating units that were expected to be available for summer 2021. 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:
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 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

All cases were modified 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.

Alabama:
- Area Max
- Central AL, East AL, North AL, Northeast AL, South AL, West AL

Georgia:
- Bowen Unit 2 on @minimum, except for the Summer Renewables Off case as fully on
- Scherer 1-3 on @minimum output
- Rocky Mountain off
- Wansley off
- Yates 6 & 7 on @minimum output, except for the Summer Renewables Off case as fully on
- Vogtle 2 off @minimum, except for the Summer Renewables Off case as full on
- Gaston 1-5 @max output
- Lindsay Hill, Central Alabama, Harris – running economically
- Hydro – still modeled at minimum flow
- Renewables on and off still observed

5. Extreme Event cases

Summer Peak 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 corridors.

6. Renewable cases

Summer Peak and Shoulder cases were created to include renewables, including biomass and solar units, turned on and turned off.

All of these cases were economically dispatched using Southern Company's Designated Network Resources for 2021 and the individual generating units' cost data.

SUMMER OPERATING STUDY ASSUMPTIONS

The following assumptions were used for the 2021 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 95ºF ambient adjusted ratings as used by Transmission Planning except for the Hot Weather (T) scenario, which uses the 104°F ambient adjusted ratings.

4. De-rates were applied to the Fitzgerald - North Tifton, Lagrange #6 – Lagrange #11, & Lagrange Primary – Lagrange #6 115 kV lines.

Screening Procedure

1. SOS Load Flow Cases:
   - H, S, T base cases as defined above
   - H, S cases with additional single and multiple generator unit outages, units detailed below
   - 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 (104ºF ambient) in normal-weather peak, all cases
   - No element out using Rate B (95ºF ambient) in normal-weather peak, all cases
   - Contingency N-1 (one element out) using Rate B (95ºF ambient) in all cases excluding Hot Weather (T) and Extreme Event cases
   - Contingency (one element out) using Rate B (95ºF ambient) in re-dispatched cases with one or more generation units out (listed below) in S 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

Farley Unit 1 outage	FAR1
Franklin Unit 3 outage	FRK3
Hatch Unit 1 outage	HAT1
Hatch Unit 2 outage	HAT2
Lansing Smith Unit 3 outage	LAN3
Jack McDonough Unit 4 outage	MCD4
Jack McDonough Unit 6 outage	MCD6
Scherer Unit 4 outage	SCH4
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	FRK123
West Point Dam Hydro Units outage	WPD1
Bowen 1, 4	BOW1N4

5. Autobank Out Cases

Autobank	Case Name
[redacted]	

[redacted]

6. Special Sensitivity cases – Hydro and Import

Sensitivity	Case Name
Maximum West-East flows	MXWEST_Mod

7. Extreme Events

Elements Out	Contingency Name
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
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[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

2021 Georgia Limiting Facilities
(Contingency Thermal Limitations)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

* Plant Bowen Procedure reduces total output to 1400 MW for loss of ROW. 3841 Bowen 1 350MW, 3842 Bowen 2 300 MW, 3843 Bowen 3 379 MW, 3844 Bowen 4 385 MW.

2020 Georgia Limiting Facilities
(Contingency Voltage Limitations)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[C2]

2019 - 2021

SYSTEM PERFORMANCE

Major Outages

The table below lists the major outages for years 2019, 2020, and 2021 based on the outage duration measured in MVA minutes. Georgia Power is defining a major outage as an outage with event duration greater than 10,000 MVA minutes.

[redacted]

[redacted]

[redacted]

[redacted]

Major Event Summary

[redacted]

[redacted]

[D]

GEORGIA ITS

[D1]

GEORGIA ITS
TEN YEAR TRANSMISSION
EXPANSION PLAN
(2022 – 2031)

Georgia Projects

(Includes ITS & Savannah Projects)

2022 – 2031

Transmission Planning

Southern Company Services

FALL 2021

Southern Company

CONTENTS

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	1	0.8	1	0.8
230	1	14	2	29.5
115	2	22.8	2	22.8
Total	**4**	**37.6**	**5**	**53.1**

Transmission Lines to be Rebuilt / Reconductored on Existing Right-of Way				
Voltage (kV)	Lines	Miles	Lines	Miles
500	0	0	0	0
230	6	143.1	6	143.1
115	21	233.1	27	273.1
Total	**27**	**376.2**	**33**	**416.2**

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	0	0	0	0
Total	**0**	**0**	**0**	**0**

Transformers to be installed (low side ≥ 115kV)				
	Units		Units	
New	1		1	
Upgrade	2		5	

New Capacitor Banks to be Installed				
Voltage (kV)	Units	MVAR	Units	MVAR
230	0	0	0	0
115	2	105	2	105

New Series Reactors to be Installed				
Voltage (kV)	Units		Units	
230	1		1	
115	2		2	

New Shunt Reactors to be Installed				
Voltage (kV)	Units		Units	
230	0		0	
115	1		1	

New Static VAR Systems to be Installed				
Voltage (kV)	Units		Units	
230	2		2	
115	0		0	

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	Year	TEAMS Number	Project Name	Need Date 2021	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2024	12016	ARKWRIGHT - LLOYD SHOALS 115 KV LINE RECONDUCTOR	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	2022	14349	AUSTIN DRIVE - MORROW 115 KV REBUILD	12/1/2022	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	2024	17294	AVALON JUNCTION - BIO 115 KV REBUILD	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	2024	18670	BANKS CROSSING - POND FORK 115 KV	6/1/2024	GTC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2022	18157	BAXLEY - JESUP 115KV REBUILD	6/1/2022	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
201	2026	18960	BLANKETS CK.- WOODSTOCK 115-KV LN REBLD, (WOODSTK-LITTLE RVR)	6/1/2026	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2030	18153	BONAIRE PRIMARY - ECHECONNEE 115KV RECONDUCTOR	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2024	19338	BRANCH-OASIS 230KV LINE RECONDUCTOR	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2022	18239	BROADWAY - SOUTH MACON REBUILD (GRAPHIC PACK- S MACON)	6/1/2022	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2022	18886	BROADWAY & ECHECONNEE CAPACITOR BANK INSTALLATION	6/1/2022	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

213	2024	11692	BULL CREEK-VICTORY 115KV LINE RECONDUCTOR	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
208	2027	18671	CORN CRIB-LAGRANGE PRIMARY 115KV	6/1/2027	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	2027	18883	DAVIS STREET-FOWLER STREET 115KV JUMPER REPLACEMENTS	6/1/2027	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2023	18945	DOUGLAS - LAKE BEATRICE 115 KV LINE RECONDUCTOR	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
201	2030	18950	DOUGLASVILLE-WEST MARIETTA 115KV RECONDUCTOR	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
211	2024	18679	DU: DALTON CITY #12 BUS REPLACEMENT	6/1/2024	DU	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
211	2024	18851	DU: EAST DALTON - OOSTANAULA 115KV REBUILD	6/2/2023	DU	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
211	2028	10811	DU: NELSON 230/115KV AUTOBANK REPLACEMENT	6/1/2028	DU	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	2023	16897	EAST WATKINSVILLE - RUSSELL DAM 230 KV RECONDUCTOR	8/25/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	2023	18989	EAST WATKINSVILLE – RUSSELL DAM JUMPER REPLACEMENTS	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2024	19339	EATONTON PRIMARY-OASIS 230KV RECONDUCTOR	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2025	18800	ECHECONNEE - WELLSTON 115KV REBUILD	6/1/2025	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2023	18879	GEORGE DAM (USA) - HUCKLEBERRY 115KV REBUILD	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

214	2022	18419	GORDON - N. DUBLIN 115KV REBUILD (EVERGRN CH - ENGELHARD)	12/1/2022	GPC	[redacted]
206	2024	19287	GRADY-WEST END 115KV RECONDUCTOR	12/31/2024	GPC	[redacted]
216	2024	18885	GTC: DAISY - WEST VALDOSTA 230KV LINE	3/1/2024	GTC	[redacted]
212	2028	18669	GTC: DAWSON CROSSING - NELSON (WHITE) 115 KV RECONDUCTOR	6/1/2028	GTC	[redacted]
216	2024	18691	GTC: GILLIONVILLE - GREENHOUSE 115 KV LINE	6/1/2024	GTC	[redacted]
215	2022	18447	GTC: GOSHEN 230KV SERIES REACTORS	5/1/2022	GTC	[redacted]
213	2024	18774	GTC: HEARD COUNTY - TENASKA 500KV (NEW LINE)	6/1/2024	ITS	[redacted]
202	2031	18463	GTC: HOPEWELL 230/115KV AUTOBANK	6/1/2031	GTC	[redacted]
211	2023	19341	GTC: JUDY MOUNTAIN 230KV SHUNT REACTOR	6/1/2023	GTC	[redacted]
213	2027	19334	GTC: LAGRANGE - NORTH OPELIKA 230KV(APC) (NEW LINE)	6/1/2027	GTC	[redacted]
211	2023	19340	GTC: MIDDLE FORK STATIC VAR SYSTEM	6/1/2023	GTC	[redacted]
216	2024	18884	GTC: RACCOON CREEK - SCOOTER 230KV JUMPER REPLACEMENT	6/1/2024	GTC/MEAG	[redacted]
216	2026	15882	GTC: SAWHATCHEE SWITCH REPLACEMENT (BLAKELY PRIMARY-WEBB 115KV)	6/1/2026	GTC	[redacted]

206	2030	18889	JEFFERSON STREET#3-NORTHWEST RECONDUCTOR	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
218	2024	11821	JESUP - LUDOWICI PRIMARY 115 KV RECONDUCTOR	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
218	2024	18668	JESUP - OFFERMAN 115KV RECONDUCTOR	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2023	15687	KETTLE CREEK - PINE GROVE 115KV LINE RECONDUCTOR PHASE ONE	12/31/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2030	16589	KETTLE CREEK - PINE GROVE 115KV LINE RECONDUCTOR PHASE TWO	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
218	2024	19028	KINGSLAND BANK C REPLACEMENT	6/2/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	2024	18772	KLONDIKE 500KV SWITCH REPLACEMENT	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
219	2025	18689	LITTLE OGEECHEE REDUNDANT RELAY	6/1/2025	SAV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2022	18315	LUMPKIN SOLAR IMPROVEMENTS (GI-110)	6/1/2022	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	2023	10194	MCEVER ROAD - SHOAL CREEK 115KV REBUILD - PHASE 2	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
211	2023	19305	MCGRAU FORD STATIC VAR SYSTEM	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
213	2024	18832	MEAG: FORTSON 230KV REDUNDANT RELAY	12/31/2024	MEAG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2024	18492	MITCHELL - NORTH TIFTON 230KV RECONDUCTOR	3/1/2024	ITS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2024	18495	MITCHELL - RACCOON CREEK 230 KV RECONDUCTOR	3/1/2024	GTC/MEAG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

202	2026	17975	NORCROSS - SNELLVILLE PRIMARY 115KV (REBUILD)	6/1/2026	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
201	2024	13653	NORTH MARIETTA - SMYRNA (BLACK & WHITE) 115KV RECONDUCTORS	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2024	18690	PALMYRA REACTOR REMOVAL	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	2024	19019	PINE GROVE PRIMARY BANK B REPLACEMENT	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
211	2022	17678	POSSUM BRANCH 230/115 KV PROJECT	5/1/2022	GTC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2023	15698	SINCLAIR DAM - WARRENTON 115KV RECONDUCTOR PHASE I	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	2023	18329	SITE "H" ENHANCED PHYSICAL SECURITY	12/31/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
215	2023	14271	THOMSON PRIMARY - WARRENTON PRIMARY 115 KV WHITE LINE REBUILD	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
215	2023	19388	WEST AUGUSTA 115KV SUBSTATION: OVERSTRESSED BREAKER	6/1/2023	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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	Project Name	Last Year's Need Date	Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
202	18448	BAY CREEK - CONYERS 230KV RECONDUCTOR	6/1/2025	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	15371	BRANCH - TIGER CREEK 230 KV (BLACK&WHITE) SERIES REACTORS	12/1/2021	GTC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
202	18450	BULL SLUICE - GLAZE DRIVE 230KV RECONDUCTOR	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	16404	CLARKSTON - SCOTTDALE 115KV LINE UPGRADE	6/1/2028	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	18449	CONYERS - KLONDIKE 230KV RECONDUCTOR	6/1/2028	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	16920	CONYERS 230KV BUS REPLACEMENT (on CONYERS - KLONDIKE 230 KV)	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	18700	DAWSON CROSSING - GAINESVILLE #1 115 KV	6/1/2027	GTC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
208	10452	JONESBORO - OHARA 230-KV RECONDUCTOR & UPGRADES	6/1/2025	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	12602	KLONDIKE - MORROW 230KV LINE RECONDUCTOR	6/1/2027	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
208	17791	LINE CREEK - FAIRBURN 2 115KV LINE UPGRADE	6/1/2021	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
206	13753	MEAG: ALCOVY ROAD - SKC 115 KV RECONDUCTOR	6/1/2024	MEAG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

202	18451	NORTH SPRINGS SWITCH AND BUS REPLACEMENT	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
208	18454	OHARA 230 KV BUS TIE BREAKERS	6/1/2024	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
208	15239	S. COWETA - S. GRIFFIN 115KV LN. RECOND, (S. COWETA-BROOKS)	6/1/2029	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
215	14222	THOMSON PRIMARY SECOND 230/115 KV BANK	6/1/2030	GPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

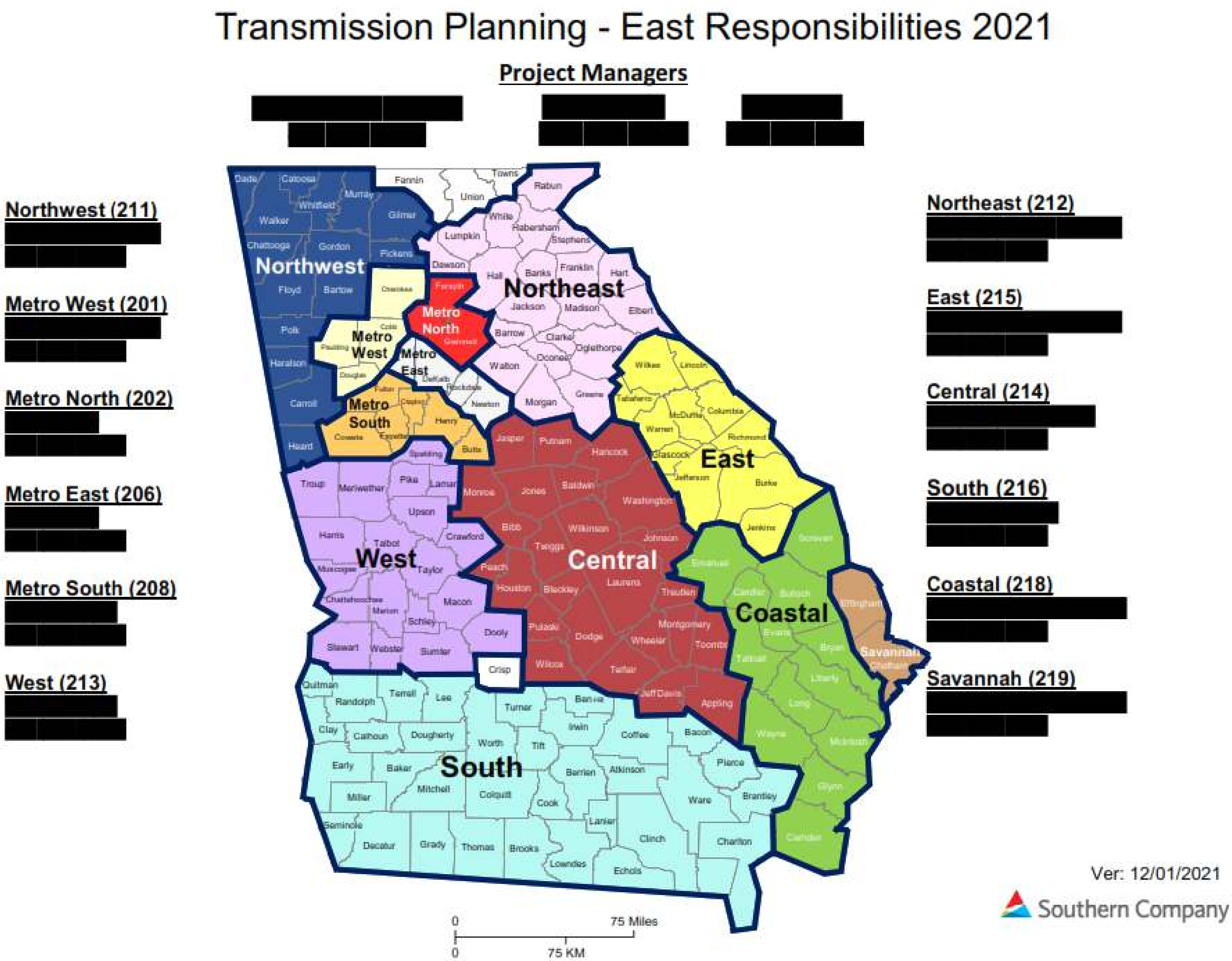
D. Completed Projects List – Removed from the Current 10 Year Expansion Plan

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	Project Name	Last Year's Need Date	Previous IRP Need Date
215	17790	ADD SECOND PILOT TO AUGUSTA CORPORATE PARK - VOGTLE 230KV	3/1/2021	N/A
214	17771	BONAIRE - KATHLEEN 115KV RECONDUCTOR	7/1/2023	N/A
206	16919	BOULEVARD - NORCROSS 115 KV SWITCH REPLACEMENT	6/1/2021	N/A
216	17573	DAWSON PRIMARY: GTC LINE REROUTE AND UPGRADES	6/1/2021	N/A
214	10442	GORDON - SANDERSVILLE #1 115 KV LINE UPGRADE	12/1/2021	6/1/2022
215	18094	GOSHEN - VOGTLE 230KV SECOND PILOT	11/1/2021	N/A
202	10129	LAWRENCEVILLE - NORCROSS 230KV LINE RECONDUCTOR	6/1/2021	6/1/2022
218	13024	LIVE OAK - STATESBORO PRIMARY 115KV REBUILD	12/1/2021	6/1/2023
213	18692	MEAG: FORTSON 500KV RELAY REPLACEMENT	12/31/2021	N/A
206	14349	REPLACE JUMPERS AT RIVER ROAD (AUSTIN DRIVE - MORROW 115 KV REBUILD)	6/1/2021	N/A
214	18137	SHADDOCK CREEK 115 KV CAPACITOR BANK	12/31/2021	N/A
215	14663	WADLEY PRIMARY 500/230KV PROJECT	12/1/2021	6/1/2021

Figure 1 SCS Transmission Planning - East Responsibilities



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.

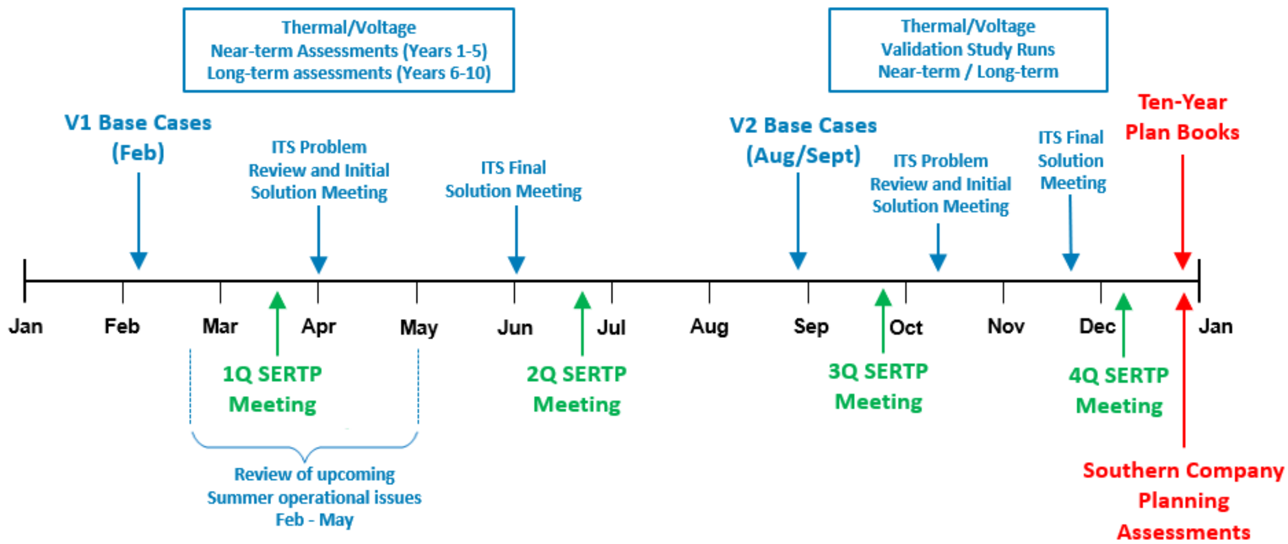
Maintaining System Models

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 2021 Series ITS Load Forecast

		2021 SERIES LOAD FORECAST						
		Summer Coincident Peak						
		Last Update:	11/18/2020					
YEAR	(A) GPC Coincident Load Forecast @ Generator	(B) DALTON Coincident Load Forecast @ Generator	(C) MEAG Coincident Load Forecast @ Generator	(D) GTC Coincident Load Forecast @ Generator	(E) Total ITS Coincident Load Forecast @ Generator	(F) Total ITS Coincident Load Forecast @ Sub High-side	% growth	Year to Year MW Growth
2021	[redacted]							
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
			Transmission Loss Factor =		1.87%			

A = GPC Coincident Peak Load (supplied by SCS,I)
B = DALTON Coincident Peak Load (supplied by GPC)
C = MEAG Coincident Peak Load (supplied by MEAG)
D = OPC Coincident Peak Load (supplied by GTC)
E = A + B + C + D
F = E * (1- Transmission Loss Factor)

Figure 3 Total 2021 Series ITS Summer Coincident at the Generator

[redacted]

Load Forecast by Zone in Models

Table 6 10 Year Load Forecast by Zone

ZONE	REGION	2021 MW	2031 MW	10 YEAR GROWTH %	COMPOUND AGR %
201	METRO WEST	3256	3469	6.54%	0.636%
202	METRO NORTH	4201	4479	6.62%	0.643%
206	METRO EAST	3063	3246	5.98%	0.582%
208	METRO SOUTH	2685	2852	6.22%	0.605%
211	NORTHWEST	2141	2273	6.17%	0.600%
212	NORTHEAST	2616	2876	9.94%	0.952%
213	WEST	1658	1776	7.12%	0.690%
214	CENTRAL	2133	2239	4.97%	0.486%
215	EAST	1265	1346	6.40%	0.623%
216	SOUTH	2377	2534	6.61%	0.642%
218	COASTAL	1226	1311	6.93%	0.673%
219	SAVANNAH	1254	1352	7.82%	0.755%
TOTAL		**27,873**	**29,752**		

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 load assumption was anticipated to result in the highest system stress, with a significant portion of energy-limited resources projected to be off-line. Additionally, System Off-Peak cases representing 70% of the summer peak demand were evaluated. All System peak, Off-Peak, and Shoulder 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 ratings.

All projects resulting from Steady State analysis to address any identified deficiencies have been added to the list of projects in Section IV E, 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:	3Ø	
		1. Generator		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.
		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:	3Ø	
		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	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 criteria
P7 **Multiple Contingency (Common Structure)**	Normal System	The loss of:	SLG	
		1. Any two adjacent (vertically or horizontally) circuits on common structure		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.
		2. Loss of a bipolar 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.
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. 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 NERC 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 for the 2021 studies was Off-Peak conditions (70% of peak load, solar units at 100% of nameplate capacity, hydro units not generating). 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. In addition to the NERC Compliance and Sensitivity cases, the ITS planners evaluated two System Shoulder conditions, with load at 93% of System peak. The Daylight Shoulder case represents the hour of the peak day just before hydro units ramp up. The Dusk Shoulder case represents the hour of the peak day when solar generation has just ramped down and hydro generation is ramping up. [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]

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:	3Ø	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.
		1. Generator		
		2. Transmission Circuit		
		3. Transformer		
		4. Shunt Device		
		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:	3Ø	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.
		1. Generator		
		2. Transmission Circuit		
		3. Transformer		
		4. Shunt Device		

		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	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.
		1. Generator		
		2. Transmission Circuit		
		3. Transformer		
		4. Shunt Device		
		5. Bus Section		
		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:	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.
		1. Generator		
		2. Transmission Circuit		
		3. Transformer		
		4. Shunt Device		
		5. Bus Section		
P6 Multiple Contingency	Loss of one of the following followed by System adjustments.	Loss of one of the following:	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
		1. Transmission Circuit		

(Two overlapping singles)	1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single pole of a DC line	2. Transformer 3. Shunt Device		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.
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure	SLG	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.
		2. Loss of a bipolar DC line		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.
Extreme Events				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: 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]

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.

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.

Northern Interface

For the Northern interfaces of MISO, TVA, Duke, SCPSA and SCEG/Dominion, 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.

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

Year	Peak Case Transfer Amount (MW)
2022	[redacted]
2023 - 2031	[redacted]

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 reviewed 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 table 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

Line Name (Breaker to Breaker)	OG Start Date	OG End Date	Procedure
ATHENA - UNION POINT PRIMARY 115 KV	6/1/2021	10/1/2024	[redacted]
ATHENA - UNION POINT PRIMARY 115 KV	6/1/2024	12/1/2024	[redacted]
AUGUSTA CORPORATE PARK - GOSHEN 230KV	6/1/2024	12/1/2024	[redacted]
AUGUSTA CORPORATE PARK - VOGTLE 230KV	6/1/2024	12/1/2024	
BLANKETS CREEK - WOODSTOCK 115 OPERATING GUIDE	6/1/2021	10/1/2025	
BONAIRE PRIMARY - KATHLEEN 230KV OPERATING GUIDE	6/1/2024	6/1/2025	[redacted]
CONYERS-KLONDIKE 230KV	6/1/2024	10/1/2025	[redacted]
DOUGLAS - LAKE BEATRICE 115KV	6/1/2025	10/1/2025	[redacted]
EATONTON PRIMARY - OASIS 230KV LINE OPERATING GUIDE	6/1/2023	6/1/2024	[redacted]
ECHECONNEE - WELLSTON 115 KV	6/1/2024	6/1/2030	[redacted]
GORDON - NORTH DUBLIN 115 KV	3/1/2022	6/1/2023	
GOSHEN - VOGTLE 230 KV	6/1/2024	12/1/2024	[redacted]
JESUP - LUDOWICI PRIMARY 115KV	6/1/2025	10/1/2029	
KLONDIKE-NORCROSS 500KV	6/1/2024	10/1/2024	[redacted]

KLONDIKE-SCHERER 500KV	6/1/2024	12/1/2024	[redacted]
MCEVER RD - SHOAL CREEK 115 KV	6/1/2022	10/1/2022	[redacted]
NORTH MARIETTA - SMYRNA (WHITE) 115 KV	6/1/2022	6/1/2024	[redacted]
RACCOON CREEK - SCOOTER 230KV	6/1/2024	10/1/2024	[redacted]
THOMSON PRIMARY - WARRENTON PRIMARY (WHITE 115 KV)	6/1/2022	10/1/2022	[redacted]

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:

A. project justification,
B. schedule for implementation (start date), and
C. expected required in-service date.
D. For transmission improvements, the start date is to provide necessary lead time to ensure the expected required in-service date can be met.

GTC: MIDDLE FORK STATIC VAR SYSTEM

TEAMS # 19340

Need Date 12/1/2023 **Start Date** 12/1/2021

Description

Install a +150/-150 MVAR STATCOM connected to the 230 kV bus at Middle Fork.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

MCGRAU FORD STATIC VAR SYSTEM

TEAMS # 19305

Need Date 12/1/2023 **Start Date** 12/1/2021

Description

Install a +150/-150 MVAR STATCOM connected to the 230 kV bus at McGrau Ford.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

SITE "H" ENHANCED PHYSICAL SECURITY

TEAMS # 18329

Need Date 12/31/2023 **Start Date** 2/1/2022

Description

Install enhanced physical security equipment to include radar, cameras, perimeter lighting, no cut/climb fencing, trench cover locks, and all necessary material required.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

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.

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

WEST AUGUSTA 115KV BREAKER REPLACEMENT

TEAMS # 19388

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

Description

At West Augusta, replace existing breaker 106228 on the Goshen 115 kV line with a 40kA or higher rated breaker.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

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.

AVALON JUNCTION - BIO 115 KV REBUILD

TEAMS # 17294

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

Description

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

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

Delayed from 2022

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

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.

ARKWRIGHT - LLOYD SHOALS 115 KV LINE RECONDUCTOR

TEAMS # 12016

Need Date 6/1/2024 **Start Date** 6/1/2021

Description

Reconductor the Arkwright - Lloyd Shoals 115kV line with 795 ACSR 100C.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

AUSTIN DRIVE - MORROW 115 KV (REBUILD)

TEAMS # 14349

Need Date 12/1/2022 **Start Date** 1/1/2020

Description

Rebuild the Austin Drive - River Road section with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BANKS CROSSING - POND FORK 115 KV

TEAMS # 18670

Need Date 6/1/2024 **Start Date** 6/1/2021

Description

Build new 115 kV line from McClure Industrial to structure 21A/B on the East Maysville tap (about 3 miles). Close normally open switch at Ridgeway Church Road to establish the Banks Crossing - Pond Fork 115 kV line. All new conductor should be 100°C 1351 ACSR Martin.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BAXLEY - JESUP 115KV REBUILD

TEAMS # 18157

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

Description

Rebuild the Baxley - Brentwood section, 14.9 miles of 100 degrees C 4/0 ACSR Penguin conductor, using 100°C 795.0 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

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

TEAMS # 18960

Need Date 6/1/2026 **Start Date** 6/1/2024

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]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

Delayed from 2024

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BONAIRE PRIMARY - ECHECONNEE 115 KV RECONDUCTOR

TEAMS # 18153

Need Date 6/1/2030 **Start Date** 1/1/2029

Description

Reconductor the Bonaire Primary - Russell Parkway Junction section of the line (2.3 mi) with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BRANCH - OASIS 230KV LINE RECONDUCTOR

TEAMS # 19338

Need Date 6/1/2024 **Start Date** 2/15/2022

Description

Reconductor the Branch-Forest Lake-Eatonton Primary line sections (9.73 miles) with 160°C ACSS conductor. Replace the jumpers at Branch and the jumpers and main bus at Eatonton Primary with 2-1590 AAC.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BROADWAY - SOUTH MACON REBUILD (GRAPHIC PACK- S MACON)

TEAMS # 18239

Need Date 6/1/2022 **Start Date** 8/15/2021

Description

Rebuild the South Macon - Graphic Packaging line section (1.4 mles) with 100°C 1351 ACSR Martin conductor.

Replace the 636 ACSR jumpers at Graphic Packaging with 1590 AAC.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BROADWAY & ECHECONNEE CAPACITOR BANK INSTALLATION

TEAMS # 18886

Need Date 6/1/2022 **Start Date** 9/15/2021

Description

Install a 2-step 60 MVAR (30+30) 115 kV capacitor bank at Broadway and a single-step 45 MVAR capacitor bank at Echeconnee.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

BULL CREEK - VICTORY DRIVE 115 KV LINE RECONDUCTOR

TEAMS # 11692

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

Description

Reconductor 1.3 miles of 115 kV line with 100°C 795 ACSR Drake conductor from Victory Drive to Chloride.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

CORN CRIB - LAGRANGE 115KV RECONDUCTOR

TEAMS # 18671

Need Date 6/1/2027 **Start Date** 6/1/2024

Description

Reconductor the Lagrange- Ragland St.- Lagrange 3 - North Lagrange section (4.6 miles) with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

DAVIS STREET-FOWLER STREET 115KV JUMPER REPLACEMENTS

TEAMS # 18883

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

Description

Replace 750AAC jumpers at Davis Street with 1590AAC jumpers.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

DOUGLAS - LAKE BEATRICE 115KV LINE SEGMENT REBUILD

TEAMS # 18945

Need Date 6/1/2023 **Start Date** 1/5/2022

Description

Rebuild 3.4 miles of 336 ACSR, from Douglas to Bushnell, with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

DOUGLASVILLE - WEST MARIETTA 115 KV RECONDUCTOR

TEAMS # 18950

Need Date 5/1/2030 **Start Date** 6/1/2028

Description

Reconductor the Douglasville - Lithia Springs section (2.3 miles) using 100°C 1033 ACSR Curlew conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

DU: DALTON CITY #12 BUS REPLACEMENT

TEAMS # 18679

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

Description

DU: Replace 477 ACSR bus and jumpers conductor with more capable conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

DU: EAST DALTON - OOSTANAULA 115 KV REBUILD

TEAMS # 18851

Need Date 6/1/2023 **Start Date** 7/7/2021

Description

Rebuild 15.6 miles of 100°C 477 ACSR from Oostanaula to Dalton #9 using 200°C 795 ACSS.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

DU: NELSON 230/115KV AUTOBANK REPLACEMENT

TEAMS # 10811

Need Date 6/1/2028 **Start Date** 1/1/2025

Description

DU: Replace both existing 230/115kV autotransformers with new 400MVA 230/115kV autotransformers.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

EAST WATKINSVILLE - RUSSELL DAM 230 KV JUMPER REPLACEMENTS

TEAMS # 18989

Need Date 5/1/2023 **Start Date** 1/30/2022

Description

Replace the existing jumpers from 90° C 1-1590 AAC with 90° C 2-1590 AAC or equivalent at Russell Dam and East Watkinsville substations on the East Watkinsville - Russell Dam 230 kV line. GTC will perform replacement at East Watkinsville.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project. This is a companion project to TEAMS 16897, which reconductors the East Watkinsville - Russell Dam 230 kV line.

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

EAST WATKINSVILLE - RUSSELL DAM 230 KV RECONDUCTOR

TEAMS # 16897

Need Date 8/25/2023 **Start Date** 6/1/2021

Description

Replace the 1351.5 ACSR/SD Self Damping Conductor on the the East Watkinsville - Russell Dam 230 kV line with 200°C 1351.5 ACCR Martin conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

EATONTON PRIMARY - OASIS 230KV RECONDUCTOR

TEAMS # 19339

Need Date 6/1/2024 **Start Date** 2/15/2022

Description

Reconductor the Eatonton Primary - Oasis 230 kV line (25.6 miles) wih 160°C 1351.5 ACSS conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

ECHECONNEE - WELLSTON 115KV LINE RECONDUCTOR

TEAMS # 18800

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

Description

Reconductor the South Warner Robins - Wellston section (1.2 miles) with 100°C 1351.5 ACSR Martin conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GEORGE DAM (USA) - HUCKLEBERRY 115KV REBUILD

TEAMS # 18879

Need Date 6/1/2023 **Start Date** 6/9/2021

Description

GPC: Rebuild the Huckleberry SS - George Dam secrion (8.9 miles) using 100°C 1351.5 ACSR Martin conductor. Replace switches, bus and jumpers at Fort Gaines.
GTC: Replace jumpers at George Dam.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GORDON - N. DUBLIN 115KV REBUILD (EVERGRN CH - ENGELHARD)

TEAMS # 18419

Need Date 12/1/2022 **Start Date** 1/1/2022

Description

Rebuild the Engelhard (McIntyre) Junction - Evergreen Church (Str. # 174) section of the Gordon - North Dublin 115 kV line with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GRADY - WEST END 115 KV RECONDUCTOR

TEAMS # 19287

Need Date 12/31/2024 **Start Date** 6/1/2022

Description

Reconductor the Grady - West End 115 kV line, 2.6 miles, using 160°C 636 ACSS conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: DAISY - WEST VALDOSTA 230KV LINE REBUILD

TEAMS # 18885

Need Date 3/1/2024 **Start Date** 12/31/2021

Description

GTC: Reconductor 16.5 miles of 1033 ACSR Curlew conductor using 1351 ACSR Martin conductor. At Spain (GTC), replace the 1590 AAC jumpers. At West Valdosta (GPC), replace the 1590 AAC 230kV bus and jumpers.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: DAWSON CROSSING - NELSON (WHITE) 115 KV RECONDUCTOR

TEAMS # 18669

Need Date 6/1/2028 **Start Date** 6/1/2025

Description

GTC: Rebuild the Dawson Crossing - Etowah - Reavis Mountain sections, about 14 miles, using 100°C 795 ACSR Drake conductor. GPC will make any necessary relaying changes at Dawson Crossing.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Adding the Dawson Crossing - Etowah section again

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: GILLIONVILLE - GREENHOUSE ROAD 115 KV LINE

TEAMS # 18691

Need Date 6/1/2024 **Start Date** 6/1/2021

Description

GTC will construct a new 19.8-mile 115kV line from Greenhouse Rd to Gillonville Substation using 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Delayed from 2023

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: GOSHEN 230 KV SERIES REACTORS

TEAMS # 18447

Need Date 5/1/2022 **Start Date** 1/1/2021

Description

GTC: Install a 1.5% series reactor at Goshen substation in the South Augusta (White) 230 kV line terminal.
GPC: Make necessary relaying changes at South Augusta.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Delayed from 12/1/2021

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: HEARD COUNTY - TENASKA 500 KV (SECOND LINE)

TEAMS # 18774

Need Date 6/1/2024 **Start Date** 12/1/2021

Description

GTC: Build a second Heard County - Tenaska 500 kV line, 0.8 miles, with 100C (3) 1113 ACSR Bluejay conductors per phase. Add a 500 kV ring-bus breaker at Heard County.
GPC: Add a 500 kV ring-bus breaker at Tenaska.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: HOPEWELL 230/115KV AUTOBANK

TEAMS # 18463

Need Date 6/1/2031 **Start Date** 6/1/2027

Description

GTC: Replace 280 MVA Bank A with a 400 MVA autobank.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: JUDY MOUNTAIN SHUNT REACTOR

TEAMS # 19341

Need Date 6/1/2023 **Start Date** 2/1/2021

Description

Install a 150 MVAR shunt reactor set at Judy Mountain connected to the 230 kV bus.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: LAGRANGE - NORTH OPELIKA 230 KV (NEW LINE)

TEAMS # 19334

Need Date 6/1/2027 **Start Date** 12/1/2021

Description

Build a new Lagrange - North Opelika (APC) 230kV line, 29.4 miles, with 100C ACSR 1351.5 Martin Conductor. GTC will construct the 15.5-mile section from Lagrange to the Metering Point at the Georgia - Alabama border. The Metering Point will be owned by GPC. APC will construct the 230kV line from the Metering Point to North Opelika.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: RACCOON CREEK - SCOOTER 230KV LINE JUMPER REPLACEMENT

TEAMS # 18884

Need Date 5/1/2024 **Start Date** 1/1/2023

Description

GTC: Replace AAC Larkspur 1033.5 jumpers at Raccoon Creek on the Scooter 230kV line, with AAC 1590 jumpers that match, or surpass, the rating of 1033.5 ACSR Curlew line conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

GTC: SAWHATCHEE SWITCH REPLACEMENT

TEAMS # 15882

Need Date 6/1/2026 **Start Date** 6/1/2024

Description

GTC: Replace 600A switch 68101 at Sawhatchee substation.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

JEFFERSON STREET#3 - NORTHWEST (WHITE) 115 KV RECONDUCTOR

TEAMS # 18889

Need Date 6/1/2030 **Start Date** 1/1/2029

Description

Rebuild approximately 1.2 miles of TL with 200°C 1351 ACSS conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

JESUP - LUDOWICI PRIMARY 115-KV RECONDUCTOR

TEAMS # 11821

Need Date 6/1/2024 **Start Date** 12/31/2021

Description

Reconductor the Jesup - North Jesup section (2.6 miles) using 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

JESUP - OFFERMAN 115KV RECONDUCTOR

TEAMS # 18668

Need Date 6/1/2024 **Start Date** 4/6/2021

Description

Reconductor the entire main line except the section from Offerman to Structure 321 (17.7 miles) with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Increase scope of project to reconductor/rebuild 17.7 miles instead of 8.4 (last year). This is the whole line minus a 2.43-mile section of Linnet conductor. Moved project up from 2029 to 2024.

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

KETTLE CREEK - PINE GROVE 115KV LINE RECONDUCTOR PHASE ONE

TEAMS # 15687

Need Date 12/31/2023 **Start Date** 9/11/2020

Description

Rebuild the Kettle Creek Primary - Pearson Tap portion of the line (20.5 miles) with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Advanced from 2029

Change From Previous IRP

Delayed from 6/1/2023

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

KETTLE CREEK - PINE GROVE 115KV LINE RECONDUCTOR PHASE TWO

TEAMS # 16589

Need Date 6/1/2030 **Start Date** 6/1/2027

Description

Rebuild 21.7 miles of 50C 4/0 ACSR conductor along the North Lakeland to Pearson tap portion of the line using 100C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

Delayed from 2028

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

KINGSLAND BANK C REPLACEMENT

TEAMS # 19028

Need Date 6/1/2024 **Start Date** 10/1/2021

Description

Replace 160MVA, 230/115kV Bank C at Kingsland with a 300MVA, 230/115kV autobank.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

KLONDIKE 500KV SWITCH REPLACEMENT

TEAMS # 18772

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

Description

Replace 2500A line switch 146161 in the Norcross 500 kV line terminal at Klondike with a 4000A switch.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

LITTLE OGEECHEE REDUNDANT RELAY

TEAMS # 18689

Need Date 6/1/2025 **Start Date** 6/1/2023

Description

Add a redundant relay scheme at Little Ogeechee 230KV.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

LUMPKIN SOLAR IMPROVEMENTS (GI-110)

TEAMS # 18315

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

Description

Install two 3% series reactors on the Dawson Primary - Palmyra 115kV line at Palmyra substation.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

MCEVER ROAD - SHOAL CREEK 115KV REBUILD - PHASE 2

TEAMS # 10194

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

Description

Rebuild the 2-4/0 copper sections (approximately 2.41 miles from structure 391-411A) and the 636 portion of the line (about 1 mile from McEver Rd - structure 391) using 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

The 636 will no longer be replaced so the rebuild is no longer the whole line.

Change From Previous IRP

Advanced from 2027

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

MEAG: FORTSON 230 KV REDUNDANT RELAY

TEAMS # 18832

Need Date 12/31/2024 **Start Date** 1/1/2022

Description

Add a redundant relay scheme at Fortson. This is a small part of a larger substation modernization project.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

MITCHELL - NORTH TIFTON 230KV RECONDUCTOR

TEAMS # 18492

Need Date 3/1/2024 **Start Date** 12/31/2021

Description

GPC will reconductor 35.21 miles of 100°C 795 ACSR with 100°C 1351 ACSR Martin conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Advanced from 2026

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

MITCHELL - RACCOON CREEK 230 KV RECONDUCTOR

TEAMS # 18495

Need Date 3/1/2024 **Start Date** 3/1/2022

Description

Reconductor 7.9 miles (1.4 miles MEAG, 6.5 miles GTC) of 100°C 1351.5 ACSR with 200°C 1351.5 ACSS. GTC: Replace 1590 AAC jumpers at Raccoon Creek with 2-1590 AAC jumpers.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

NORCROSS - SNELLVILLE PRIMARY 115 KV REBUILD

TEAMS # 17975

Need Date 12/1/2024 **Start Date** 6/1/2022

Description

Rebuild 14.42 miles of the Norcross - Snellville Primary 115 kV line using 100°C 795 ACSR.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

NORTH MARIETTA - SMYRNA (BLACK & WHITE) 115KV RECONDUCTORS

TEAMS # 13653

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

Description

Reconductor the North Marietta - Lockheed Jct. sections of both lines with 150°C 636 ACSS conductor, aproximately 2.1 miles for each line.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Advanced from 2026

Change From Previous IRP

Advanced from 2025

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

PALMYRA REACTOR REMOVAL

TEAMS # 18690

Need Date 6/1/2024 **Start Date** 5/1/2023

Description

Remove the 6% reactors installed at the Palmyra Substation.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Delayed from 2023

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

PINE GROVE PRIMARY BANK B REPLACEMENT

TEAMS # 19019

Need Date 6/1/2024 **Start Date** 12/1/2021

Description

Replace 230/115 kV Bank B with a 400 MVA autobank.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

New project

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

POSSUM BRANCH 230/115 KV PROJECT

TEAMS # 17678

Need Date 5/1/2022 **Start Date** 6/1/2019

Description

GTC will construct the 14 mile, Possum Branch – Roopville 230 kV Line with 100ºC 1351 ACSR conductor and install a 230/115 kV, 400 MVA transformer at Possum Branch. GPC will construct a 230 kV ring bus switching station at Roopville.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

No change

Change From Previous IRP

No change

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

SINCLAIR DAM - WARRENTON 115KV RECONDUCTOR PHASE I

TEAMS # 15698

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

Description

Reconductor the entire Sinclair Dam - Warrenton Primary line (17.4 miles of 50°C 4/0 CU) with 100°C 795 ACSR Drake conductor. Replace 4/0 copper jumpers with AAC 1590 at Buffalo Road and South Devereux.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Scope and need date changed

Change From Previous IRP

Advanced from 2024

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

THOMSON PRI - WARRENTON PRI 115KV WHITE LINE REBUILD

TEAMS # 14271

Need Date 6/1/2023 **Start Date** 3/12/2021

Description

Reconductor the Thomson Primary - Warrenton Primary 115-kV White line (16.8 mi) with 100°C 795 ACSR Drake conductor.

Supporting Statement

[redacted]

Change From Previous Ten Year Plan

Changed from 2024 to 2023

Change From Previous IRP

New project

Estimated Cost - GPC	[redacted]
Estimated Cost - GTC	[redacted]
Estimated Cost - MEAG	[redacted]
Estimated Cost - DU	[redacted]

F. Expansion Generation Units 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.*

No projects were attributed to the expansion units included in the base cases as shown below.

Expansion Unit Locations

Case	MPC	APC	GPC	Total	Version
Winter 2027	N/A	N/A	[redacted]	[redacted]	V2
Winter 2028	N/A	N/A	[redacted]	[redacted]	V2
Winter 2029	N/A	N/A	[redacted]	[redacted]	V2
Winter 2030	N/A	[redacted]	[redacted]	[redacted]	V1
Winter 2031	[redacted]	[redacted]	[redacted]	[redacted]	V1
Daylight Shoulder 2031	N/A	N/A	[redacted]	[redacted]	V1
Dusk Shoulder 2030	N/A	N/A	[redacted]	[redacted]	Increased for V2
Dusk Shoulder 2031	N/A	[redacted]	[redacted]	[redacted]	V1
Hot Weather 2031	N/A	N/A	[redacted]	[redacted]	V1
Summer Peak 2031	N/A	N/A	[redacted]	[redacted]	V1

[redacted]

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. Interface Analysis

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.

Northern Interface and Florida Interface Studies

The Northern Interface Study and Florida Interface Study are done to ensure that the Southern Balancing Authority can maintain all long-term, firm transmission commitments and reserve margins while assessing the import and export capability of the Northern and Florida Interfaces. When a transmission project is identified by an Interface Study, the proposed recommendation will be included in the Analysis Results above.

B. 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.

C. 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 9 PSSE Output Results

Version	File Location
v1B - STRE (2022-2031)	T:\TP-East\2021_TPE_Workplan\Screen\v1B
v2B - VAL (2022-2031)	T:\TP-East\2021_TPE_Workplan\Screen\v2B

Table 70 Thermal Problem Databases

Version	File Location
v1B - STRE (2022-2031)	T:\TP-East\ 2021_TPE_Workplan\Screen\v1B\Problem Databases\2022-2031 TP-East Thermal Problems - v1B SHOTD.accdb
v2B - VAL (2022-2031)	T:\TP-East\ 2021_TPE_Workplan\Screens\v2B\Problem Databases\2022-2031 TP-East Thermal Problems - v2B SHOTD.accdb

Table 81 Voltage Problem Databases

Version	File Location
v1B - STRE (2022-2031)	T:\TP-East\ 2021_TPE_Workplan\Screens\v1B\Problem Databases\ 2021-2030 TP-East Voltage Problems - v1B SHOTD.accdb
v2B - VAL (2022-2031)	T:\TP-East\ 2021_TPE_Workplan\Screens\v2B\Problem Databases\2022-2031 TP-East Voltage Problems - v2B SHOTD.accdb

Table 9 Study Reports

Study Type	File Location
P-Events	T:\TP-Strategic\2021\Strategic\21-001_TPL-001_Compliance
Extreme Events	T:\TP-Strategic\2021\Strategic\21-001_TPL-001_Compliance\ExtremeEvents
Northern Interface	T:\TP-OATT_RegionalPlanning\Interface\2021\NIS
Florida Interface	T:\TP-OATT_RegionalPlanning\Interface\2021\FIS
Nuclear FSAR - Hatch	T:\TP-Archive\Planning General (7.021-CY15)\2021\20-002_Annual_FSAR\Hatch
Nuclear FSAR - Vogtle	T:\TP-Archive\Planning General (7.021-CY15)\2021\20-002_Annual_FSAR\Vogtle
Stability Studies	T:\TP-Stab\Generation (7.020-LOF6)\GA
Designation Studies	T:\TP-Strategic\2020

B. Generation Assumptions

Basecase Definitions

Table 10 Basecase Definitions

2021 Steady State Case Definitions					
Name	**Abbr.**	**Load Level**	**Solar**	**Hydro**	**MISO Transfer**
Summer Peak	S	Summer Peak	On	On	1000 S->N
Off Peak	O	Off Peak (70%)	On	Motor	1000 S->N
Summer NS Regional Flows	R	Summer Peak	On	On	3000 N->S
Summer SN Regional Flows	E	Summer Peak	On	On	2500 S->N
Off Peak NS Regional Flows	P	Off Peak (70%)	On	Motor	3000 N->S
Off Peak SN Regional Flows	Q	Off Peak (70%)	On	Motor	2500 S->N
Daylight Shoulder	D	Shoulder (93%)	On	Motor	1000 S->N
Shoulder	H	Shoulder (93%)	Off	50%	1000 S->N
Hot Weather	T	Hot Weather (107%)	On	On	1000 S->N
Winter	W	Winter Peak	Off	On	1000 S->N
Spring Peak	Z	Spring Peak	On	On	1000 S->N
Valley	L	Spring Valley	Off	Motor/Pump	1000 S->N
Fall Peak	F	Spring Peak	On	On	1000 S->N

Generation in Cases

The following Table is CONFIDENTIAL - Not to be shared with any Marketing Function

Table 11 ITS Generation P_{max} in Cases

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
ADDISON 1	GPC	PPA-CT	[redacted]	[redacted]
[redacted]				
ADDISON 3	GPC	PPA-CT	[redacted]	[redacted]
[redacted]				
ALBANY RENEWABLE ENERGY	GPC	PPA-Bio	[redacted]	[redacted]
[redacted]				
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	GPC	PPA-Solar	[redacted]	[redacted]
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	GPC	PPA-Solar	[redacted]	[redacted]
ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR PROJECT	GPC	PPA-Solar	[redacted]	[redacted]
ASI CLASSIC 210 MW - US 2: OLD MIDVILLE RD LLC	GPC	PPA-Solar	[redacted]	[redacted]
ASI PRIME 525 MW - US 1: BUTLER SOLAR	GPC	PPA-Solar	[redacted]	[redacted]
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	GPC	PPA-Solar	[redacted]	[redacted]
ASI PRIME 525 MW - US 1: LS PAWPAW	GPC	PPA-Solar	[redacted]	[redacted]
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	GPC	PPA-Solar	[redacted]	[redacted]
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	GPC	PPA-Solar	[redacted]	[redacted]
ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	GPC	PPA-Solar	[redacted]	[redacted]
[redacted]				
BARTLETT FERRY 1	GPC	Hydro	[redacted]	[redacted]
BARTLETT FERRY 2	GPC	Hydro	[redacted]	[redacted]
BARTLETT FERRY 3	GPC	Hydro	[redacted]	[redacted]
BARTLETT FERRY 4	GPC	Hydro	[redacted]	[redacted]
BARTLETT FERRY 5	GPC	Hydro	[redacted]	[redacted]
BARTLETT FERRY 6	GPC	Hydro	[redacted]	[redacted]

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[redacted]

BIRD DOG SOLAR	GPC	PPA-Solar
BLCKWTR SLR	GPC	Solar
BOULEVARD 1	GPC	CT
BOWEN 1	GPC	Coal
BOWEN 2	GPC	Coal
BOWEN 3	GPC	Coal
BOWEN 4	GPC	Coal
BULLDOG SOLAR	GPC	PPA-Solar
[redacted]		
DAHLBERG 10	GPC	PPA-CT
DAHLBERG 2	GPC	PPA-CT
[redacted]		
DAHLBERG 4	GPC	PPA-CT
[redacted]		
DAHLBERG 6	GPC	PPA-CT
[redacted]		
DAHLBERG 8	GPC	PPA-CT
[redacted]		
DBL RUN SLR	GPC	Solar
DECATUR SLR	GPC	Solar
[redacted]		
EXELON HEARD 1	GPC	PPA-CT
EXELON HEARD 2	GPC	PPA-CT
EXELON HEARD 3	GPC	PPA-CT
EXELON HEARD 4	GPC	PPA-CT
EXELON HEARD 5	GPC	PPA-CT
EXELON HEARD 6	GPC	PPA-CT
FLINT RIVER 1	GPC	Hydro
FLINT RIVER 2	GPC	Hydro

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

FLINT RIVER 3	GPC	Hydro	[redacted]
FORT BENNING SOLAR	GPC	Solar	[redacted]
FORT GORDON 1 SOLAR	GPC	Solar	[redacted]
FORT STEWART SOLAR	GPC	Solar	[redacted]
FORT VALLEY STATE UNIVERSITY	GPC	Solar	[redacted]
[redacted]			
GASTON 1	GPC	Oil/Gas Steam	[redacted]
GASTON 2	GPC	Oil/Gas Steam	[redacted]
GASTON 3	GPC	Oil/Gas Steam	[redacted]
GASTON 4	GPC	Oil/Gas Steam	[redacted]
GASTON A	GPC	CT	[redacted]
GEORGIA RENEWABLE POWER FRANKLIN LLC	GPC	PPA-Bio	[redacted]
GEORGIA RENEWABLE POWER MADISON	GPC	PPA-Bio	[redacted]
GOAT ROCK 3	GPC	Hydro	[redacted]
GOAT ROCK 4	GPC	Hydro	[redacted]
GOAT ROCK 5	GPC	Hydro	[redacted]
GOAT ROCK 6	GPC	Hydro	[redacted]
GOAT ROCK 7	GPC	Hydro	[redacted]
GOAT ROCK 8	GPC	Hydro	[redacted]
GREEN POWER SOLUTIONS	GPC	PPA-Bio	[redacted]
HARRIS 1 - GPC	GPC	PPA-CC	[redacted]
[redacted]			
HATCH 1	GPC	Nuclear	[redacted]
[redacted]			
HATCH 2	GPC	Nuclear	[redacted]
[redacted]			
HOBNAIL SLR	GPC	Solar	[redacted]
[redacted]			
INTERNATIONAL PAPER - FLINT RIVER	GPC	PPA-Bio	[redacted]
INTERNATIONAL PAPER - PORT WENTWORTH	GPC	PPA-Bio	[redacted]
KINGS BAY SOLAR	GPC	Solar	[redacted]
[redacted]			

LLOYD SHOALS 1	GPC	Hydro	[redacted]
LLOYD SHOALS 2	GPC	Hydro	[redacted]
LLOYD SHOALS 3	GPC	Hydro	[redacted]
LLOYD SHOALS 4	GPC	Hydro	[redacted]
LLOYD SHOALS 5	GPC	Hydro	[redacted]
LLOYD SHOALS 6	GPC	Hydro	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
LSS 50 MW - SIMON SOLAR FARM	GPC	PPA-Solar	[redacted]
LSS 50 MW - SOLAR D&D CAMILLA	GPC	PPA-Solar	[redacted]
MARINE CORPS LOGISTICS BASE	GPC	Solar	[redacted]
MAS GEORGIA LFG - PINE RIDGE	GPC	PPA-Bio	[redacted]
MAS GEORGIA LFG - RICHLAND CREEK	GPC	PPA-Bio	[redacted]
MCDONOUGH 4	GPC	CC	[redacted]
MCDONOUGH 5	GPC	CC	[redacted]
MCDONOUGH 6	GPC	CC	[redacted]
MCINTOSH 10	GPC	CC	[redacted]
MCINTOSH 11	GPC	CC	[redacted]
MCINTOSH CT 1	GPC	CT	[redacted]
MCINTOSH CT 2	GPC	CT	[redacted]
MCINTOSH CT 3	GPC	CT	[redacted]
MCINTOSH CT 4	GPC	CT	[redacted]
MCINTOSH CT 5	GPC	CT	[redacted]
MCINTOSH CT 6	GPC	CT	[redacted]
MCINTOSH CT 7	GPC	CT	[redacted]
MCINTOSH CT 8	GPC	CT	[redacted]
MCMANUS 3A	GPC	CT	[redacted]
MCMANUS 3B	GPC	CT	[redacted]
MCMANUS 3C	GPC	CT	[redacted]
MCMANUS 4A	GPC	CT	[redacted]
MCMANUS 4B	GPC	CT	[redacted]
MCMANUS 4C	GPC	CT	[redacted]
MCMANUS 4D	GPC	CT	[redacted]
MCMANUS 4E	GPC	CT	[redacted]
MCMANUS 4F	GPC	CT	[redacted]
MID GEORGIA COGEN	GPC	PPA-Cogen	[redacted]
MONROE POWER	GPC	PPA-CT	[redacted]
MOODY AFB	GPC	Solar	[redacted]
MORGAN FALLS 1	GPC	Hydro	[redacted]
MORGAN FALLS 2	GPC	Hydro	[redacted]
MORGAN FALLS 3	GPC	Hydro	[redacted]
MORGAN FALLS 4	GPC	Hydro	[redacted]
MORGAN FALLS 5	GPC	Hydro	[redacted]
MORGAN FALLS 6	GPC	Hydro	[redacted]
MORGAN FALLS 7	GPC	Hydro	[redacted]

MOSSY BESS	GPC	PPA-BES	[redacted]
N. HIGHLANDS 1	GPC	Hydro	
N. HIGHLANDS 2	GPC	Hydro	
N. HIGHLANDS 3	GPC	Hydro	
N. HIGHLANDS 4	GPC	Hydro	
OLIVER 1	GPC	Hydro	
OLIVER 2	GPC	Hydro	
OLIVER 3	GPC	Hydro	
OLIVER 4	GPC	Hydro	
PIEDMONT GREEN POWER	GPC	PPA-Bio	
[redacted]			
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	GPC	PPA-Solar	
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	GPC	PPA-Solar	
REDI 1400 MW - US 1: QUITMAN II SOLAR ENERGY CENTER	GPC	PPA-Solar	
REDI 1400 MW - US 1: QUITMAN SOLAR	GPC	PPA-Solar	
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	GPC	PPA-Solar	
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	GPC	PPA-Solar	
REDI 1400 MW - US 2: BROKEN SPOKE (Hickory Park)	GPC	PPA-Solar	
REDI 1400 MW - US 2: COOL SPRINGS	GPC	PPA-Solar	
ROBINS 1	GPC	CT	
ROBINS 2	GPC	CT	
ROBINS AFB	GPC	Solar	
[redacted]			
ROCKY MTN - PSH 1	GPC	Pump Storage Hydro	
ROCKY MTN - PSH 2	GPC	Pump Storage Hydro	
ROCKY MTN - PSH 3	GPC	Pump Storage Hydro	
[redacted]			
SCHERER 1	GPC	Coal	
[redacted]			

[redacted]				
SCHERER 2	GPC	Coal	[redacted]	[redacted]
[redacted]				
SCHERER 3	GPC	Coal	[redacted]	[redacted]
[redacted]				
SINCLAIR 1	GPC	Hydro	[redacted]	[redacted]
SINCLAIR 2	GPC	Hydro	[redacted]	[redacted]
[redacted]				
SONNY SOLAR	GPC	PPA-Solar	[redacted]	[redacted]
[redacted]				
TALLULAH 1	GPC	Hydro	[redacted]	[redacted]
TALLULAH 2	GPC	Hydro	[redacted]	[redacted]
TALLULAH 3	GPC	Hydro	[redacted]	[redacted]
TALLULAH 4	GPC	Hydro	[redacted]	[redacted]
TALLULAH 5	GPC	Hydro	[redacted]	[redacted]
TALLULAH 6	GPC	Hydro	[redacted]	[redacted]
[redacted]				
TERRORA 1	GPC	Hydro	[redacted]	[redacted]
TERRORA 2	GPC	Hydro	[redacted]	[redacted]
TMBRLAND SLR	GPC	Solar	[redacted]	[redacted]
TUGALO 1	GPC	Hydro	[redacted]	[redacted]
TUGALO 2	GPC	Hydro	[redacted]	[redacted]

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TUGALO 3	GPC	Hydro	[redacted]
TUGALO 4	GPC	Hydro	
VOGTLE 1	GPC	Nuclear	
[redacted]			
VOGTLE 2	GPC	Nuclear	
VOGTLE 2	GPC	Nuclear	
[redacted]			
VOGTLE 3	GPC	Nuclear	
[redacted]			
VOGTLE 4	GPC	Nuclear	
[redacted]			
WADLEY SLR	GPC	Solar	
WALLACE - PSH 1	GPC	Pump Storage Hydro	
WALLACE - PSH 2	GPC	Pump Storage Hydro	
WALLACE - PSH 5	GPC	Pump Storage Hydro	
WALLACE - PSH 6	GPC	Pump Storage Hydro	
WALLACE 3	GPC	Hydro	
WALLACE 4	GPC	Hydro	
Walton County (Monroe LG&E)	GPC	PPA-CT	
[redacted]			
WANSLEY 2	GPC	Coal	
[redacted]			
WASHINGTON COUNTY	GPC	PPA-CT	
[redacted]			
WILSON 1A	GPC	CT	
WILSON 1B	GPC	CT	
WILSON 1C	GPC	CT	
WILSON 1D	GPC	CT	

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WILSON 1E	GPC	CT	[redacted]
WILSON 1F	GPC	CT	
WLFSKIN SLR	GPC	Solar	
WSHCNTY SLR	GPC	Solar	
YATES 6	GPC	Oil/Gas Steam	
YATES 7	GPC	Oil/Gas Steam	
YONAH 1	GPC	Hydro	
YONAH 2	GPC	Hydro	
YONAH 3	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 / Area Max) Cases

Table 12 Generation Scenario (Unit Off) By Case Type

Generation Code	Description	Summer Peak	Shoulder	Off-Peak
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Generation Code	Description	Summer Peak	Shoulder	Off-Peak
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[D2]

ITS LOSS STUDY

2021 ITS LOSS STUDY

REPORT TO THE

TRANSMISSION PLANNING WORK GROUP

November, 2021

Members of ITS Loss Study Working Group

Randy Cobb	Georgia Power Company
Tony Tong	Georgia Power Company
Brad Heath	Municipal Electric Authority of Georgia
Tshim Tshimanga	Municipal Electric Authority of Georgia
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Ken Wofford	Georgia Transmission Corporation
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Table of Contents

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 2021. This study used ITS loss studies performed in 2018, 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

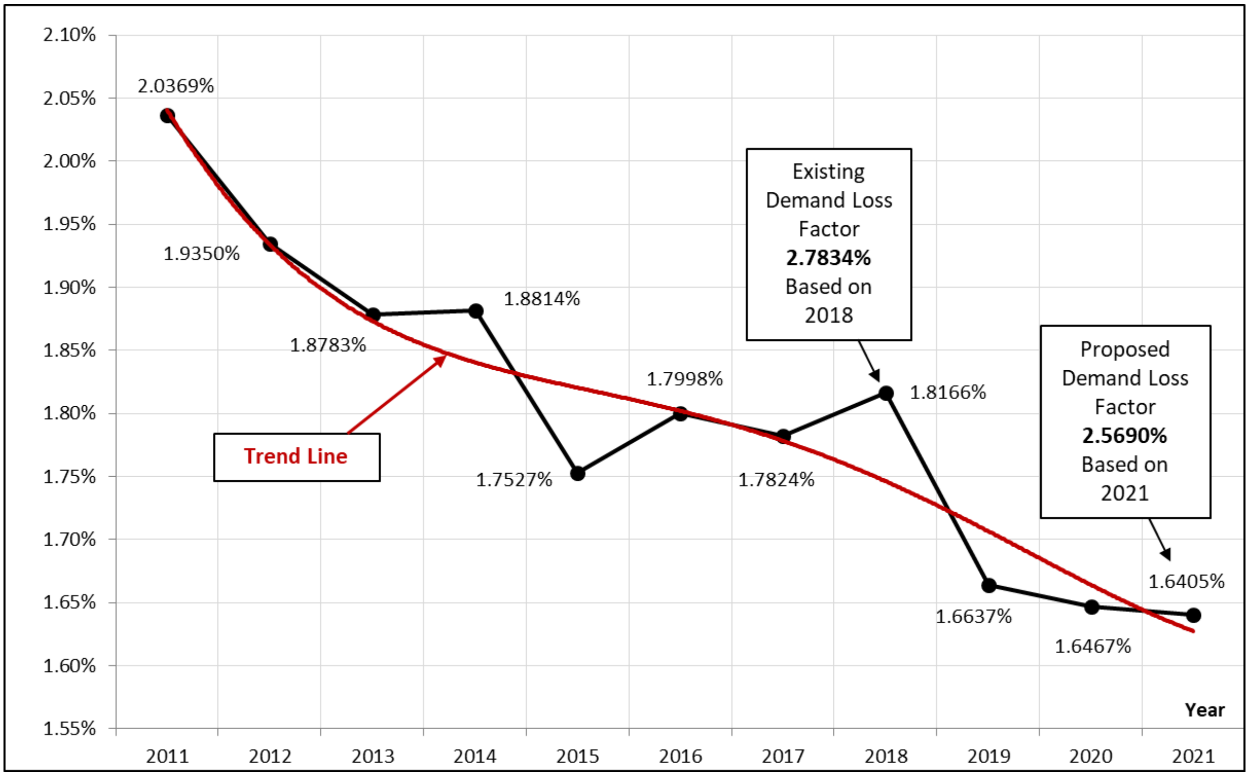
This study was conducted in two stages. The first stage consisted of modeling the transmission system (115 kV and above) as well as determining values to be used for estimating bulk transmission losses, losses in 230/xx and 115/xx transformers, losses resulting from serving station service loads, and 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 4464 load flow cases.

In an attempt to reduce anomalies, the load shapes for the six day types (144 cases from 24 hourly cases for each of the six day types) were based on an average of the loads from 2015 through 2020. And, since the 2020 load was atypical due to the pandemic, 2015 through 2019 were extrapolated to produce more "typical" values for the peak, annual energy and load factor for 2020. These 2020 values are used in some of the calculations that go into the study.

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 recent data.

The resulting loss factors are based on the v1Bs21 ITS base cases. (See Figure 1: Base Case Loss Trend).

Figure 1: Base Case Demand Loss Trend



Note: The ITS demand loss demand factor history: 2.7834% – 2019 through 2021
2.9717% – 2015 through 2018
3.2586% – 2006 through 2014
3.8060% – 1996 through 2005
4.1276% – 1987 through 1995

Figure 1 data points are the average ITS demand losses on the bulk system from the base cases. For example, the 1.6405% in 2021 in the chart is the average ITS demand losses from the S21vxxs21.sav cases. The demand loss factor, e.g., 2.5690% in 2021 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 2.5690% of the total system load, while total energy loss is 2.4189% 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 2.4016% for demand and 2.1478% for energy, which account for approximately 93.5% and 88.8% 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 0.1674% of total load, while energy losses account for 0.2711% 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

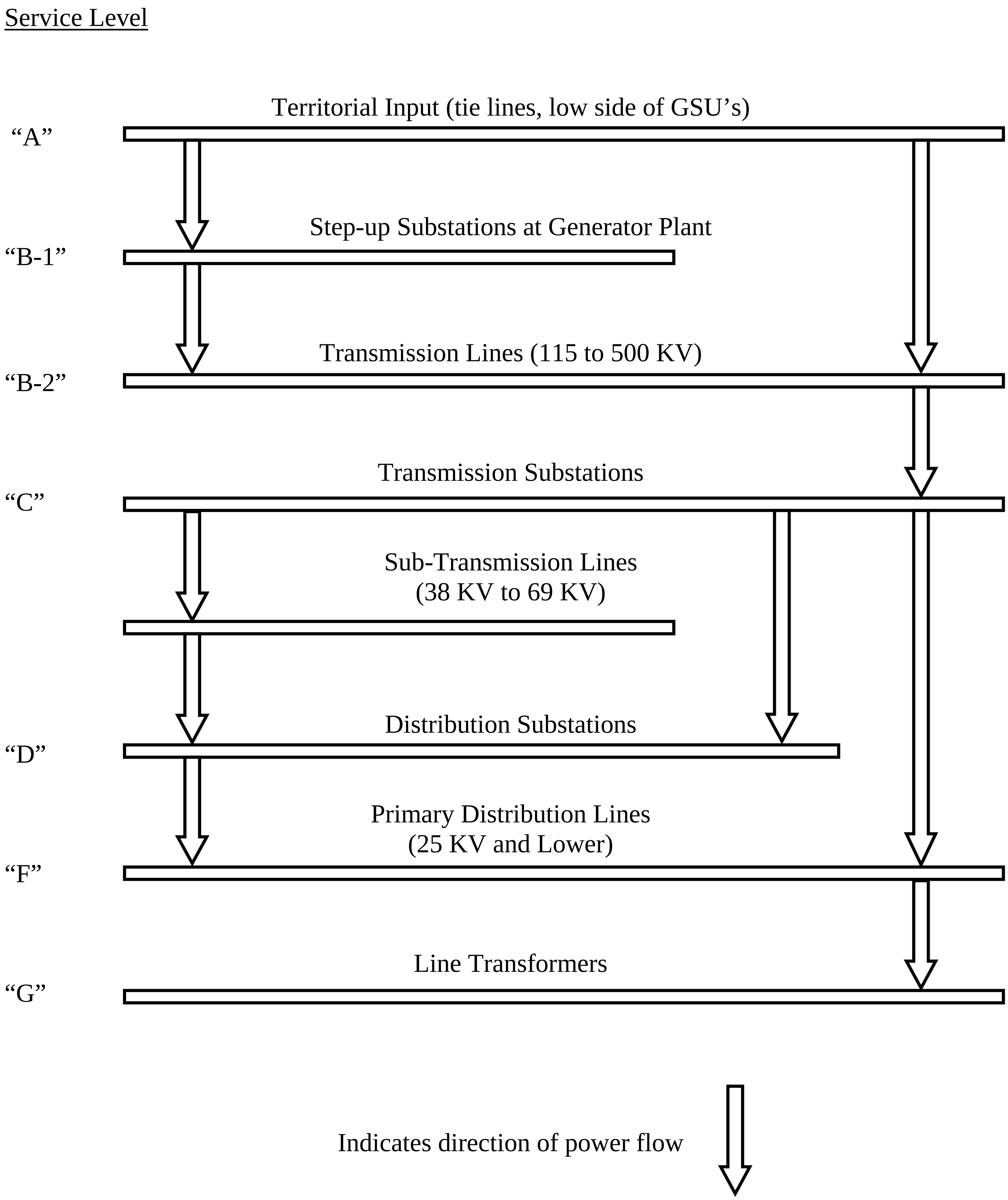


Figure 3: Service Level Designation and Power Flow Diagram

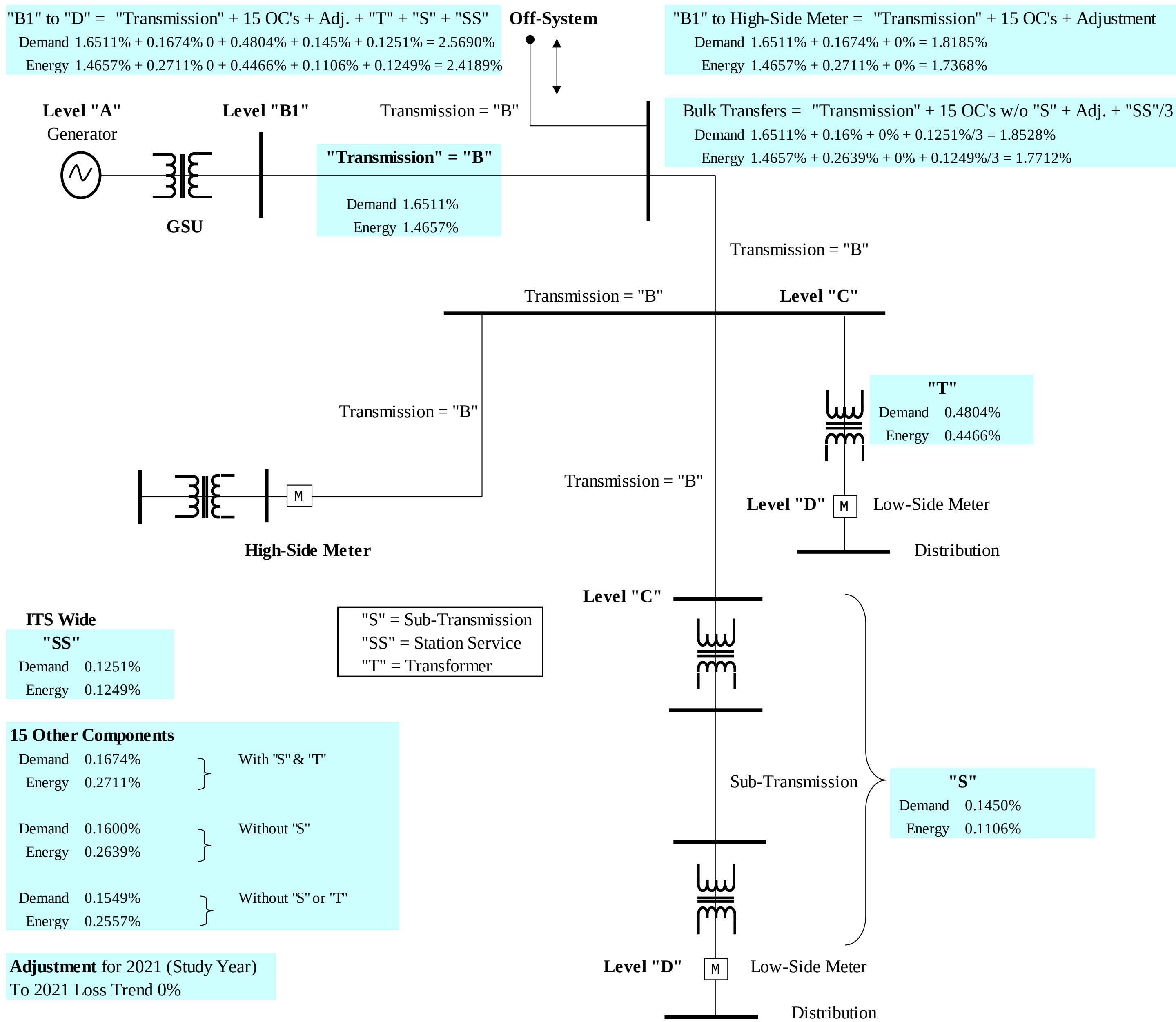


EXHIBIT 1(2021 ITS DEMAND LOSSES)

EXHIBIT 1

2021 ITS DEMAND LOSSES

B1 TO D MAJOR COMPONENTS		2021 %	2018 %	Delta %	
Bulk Transmission	B	1.6511	1.8843	-0.2332	(1)
230/xx and 115/xx Transformers	T	0.4804	0.4916	-0.0112	(2)
Station Service	SS	0.1251	0.1147	0.0104	(2)
Subtransmission (69kV and 46 kV)	S	0.145	0.1417	0.0033	
	Subtotal:	**2.4016**	**2.6323**	**-0.2307**	

OTHER COMPONENTS		2021 %	2018 %	Delta %	
Capacitors and Reactors		0.0071	0.0037	0.0034	
Catenary Adjustment		0.0359	0.0405	-0.0046	
Contact Resistances		0.0001	0.0001	0.0000	
Corona		0.0191	0.0192	-0.0001	
Deviation From Base Case Schedules		0.0000	0.0000	0.0000	
Deviation in Inadvertent Interchange		0.0232	0.0277	-0.0045	
E/M Fields		0.0050	0.0057	-0.0007	
Harmonics		0.0014	0.0017	-0.0003	
Insulator Leakage		0.0189	0.0197	-0.0008	
Line-Out Operation Adjustment		0.0038	0.0041	-0.0003	
OHGW		0.0251	0.0284	-0.0033	
Power Factor Adjustment		0.0024	-0.0273	0.0297	(2)
Temperature Compensation of Resistance		0.0000	0.0000	0.0000	
Unbalanced System Operation		0.0228	0.0252	-0.0024	
Unmetered Auxiliary Equipment		0.0026	0.0024	0.0002	
	Subtotal:	**0.1674**	**0.1510**	**0.0164**	
Total Demand Losses		2.5690	2.7833	-0.2143	
Adjustment For Trend in Base Case Losses		0.0000	0.0000	0.0000	
TOTAL TRANSMISSION DEMAND LOSSES (%)		**2.5690**	**2.7833**	**-0.2143**	

(1) System Topology changes
(2) Updated input data

	2021	2018	Delta	
Peak Demand =	25,879	26,716	-838	MW
Energy Use =	132,753,388	131,164,074	1,589,314	GWh
Load Factor =	58.40%	56.05%	2.35%	

EXHIBIT 2 (2021 ITS ENERGY LOSSES)

EXHIBIT 2

2021 ITS ENERGY LOSSES

B1 TO D MAJOR COMPONENTS		2021 %	2018 %	Delta %	
Bulk Transmission	B	1.4657	1.5330	-0.0673	(1)
230/xx and 115/xx Transformers	T	0.4466	0.4134	0.0332	(2)
Station Service	SS	0.1249	0.1256	-0.0007	
Subtransmission (69kV and 46 kV)	S	0.1106	0.1039	0.0067	(2)
	Subtotal:	**2.1478**	**2.1759**	**-0.0281**	

OTHER COMPONENTS		2021 %	2018 %	Delta %	
Capacitors and Reactors		0.0043	0.0010	0.0033	
Catenary Adjustment		0.0315	0.0327	-0.0012	
Contact Resistances		0.0001	0.0001	0.0000	
Corona		0.0845	0.0883	-0.0038	
Deviation From Base Case Schedules		0.0000	0.0000	0.0000	
Deviation in Inadvertent Interchange		0.0397	0.0500	-0.0103	(2)
E/M Fields		0.0137	0.0143	-0.0006	
Harmonics		0.0012	0.0014	-0.0002	
Insulator Leakage		0.0323	0.0352	-0.0029	
Line-Out Operation Adjustment		0.0015	0.0018	-0.0003	
OHGW		0.0221	0.0229	-0.0008	
Power Factor Adjustment		0.0003	0.0023	-0.0020	
Temperature Compensation of Resistance		0.0000	0.0000	0.0000	
Unbalanced System Operation		0.0354	0.0359	-0.0005	
Unmetered Auxiliary Equipment		0.0045	0.0043	0.0002	
	Subtotal:	**0.2711**	**0.2903**	**-0.0192**	
Total Energy Losses		2.4189	2.4663	-0.0474	
Adjustment For Trend in Base Case Losses		0.0000	0.0000	0.0000	
TOTAL TRANSMISSION ENERGY LOSSES (%)		**2.4189**	**2.4663**	**-0.0474**	

(1) System Topology changes
(2) Updated input data

	2021	2018	Delta	
Peak Demand =	25,879	26,716	-838	MW
Energy Use =	132,753,388	131,164,074	1,589,314	GWh
Load Factor =	58.40%	56.05%	2.35%	

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 4464 load flow cases.

In an attempt to reduce anomalies, the load shapes for the six day types (144 cases from 24 hourly cases for each of the six day types) were based on an average of the loads from 2015 through 2020. And, since the 2020 load was atypical due to the pandemic, 2015 through 2019 were extrapolated to produce more “typical” values for the peak, annual energy and load factor for 2020. These 2020 values are used in some of the calculations that go into the study.

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 56.08 MW or 0.2023% of the ITS connected generation, which was 27,721 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 0.2023% and B1-D losses are 2.5690%, then the proper calculation for A-D losses is:

1 - ((1 - 0.002023) x (1 - 0.025690)) = 2.7761%, not 0.002023 + .025690 = 2.7713%.

The annual energy losses on GSU's were 310,663 MWh or 0.2520% of the annual ITS generation, which was 123,271,997 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 2021 series, version 1B summer, winter, and Fall Peak power flow cases representing 2021 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 4464 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 scheduled 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 1.6511% for demand loss and 1.4657% 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 I^2R 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 15.4 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 0.4804% for demand loss and 0.4466% 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 0.1251% for demand loss and 0.1249% 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 2021 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 0.1450% for demand loss and 0.1106% 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/kvar or 0.015%. Losses in reactors, based on the available data are estimated at 2.5 W/kvar phase unit or 0.25%. In 2021, at peak, the capacitive reactive power was 5507.57 Mvar. The reactive power from shunt reactors was 408.3 Mvar.

The ITS Loss Study Working Group calculated the loss values attributable to capacitors and reactors to be 0.0071% for demand loss and 0.0043% for energy loss.

B. Catenary/Equivalencing Adjustment

Losses due to catenary distances in load flow equivalencing 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 equivalencing 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 0.0359% for demand loss and 0.0315% 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 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 2021 ITS transmission system miles data, the electrical losses attributable to corona are 0.0191% demand loss and 0.0845% 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 0.0232% for demand loss and 0.0397% 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 0.0050%. For the energy loss component, the Working Group estimates the loss factor to be 0.008% divided by the Load Factor resulting in a value of 0.0137% 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 2.47%. 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 0.0014% for demand loss and 0.0012% 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 0.0189% demand loss and 0.0323% 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 0.0038% for demand loss and 0.0015% 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 0.0251% for demand loss and 0.0221% 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 2021 base case model, the ITS power factor is calculated to be 0.9651. Based on the real time data, during the peak, the power factor was calculated to be 0.9636 (slightly worse than the value represented in the model). The Power Factor Adjustment calculated by the ITS Loss Study Working Group are 0.0024% for demand loss and 0.0003% 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 0.0228% 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 0.0354% 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 700 kVA for the entire system. The real portion of 700 kVA divided by the peak load (700 kVA * power factor) results in a value of 0.0026% for demand loss and 0.0045% for energy loss.

APPENDIX

Table 1. Unit-out Probabilities (Peak)

Rank	Units Outaged	Number of Units Out	Probability (Rounded)	Sum of Probabilities
1	No Outages	0	43.80%	43.80%
2	1-Bowen	1	19.46%	63.25%
3	1-Scherer	1	6.16%	69.41%
4	1-Franklin CC	1	4.98%	74.39%
5	1-McDonough CC	1	4.98%	79.37%
6	1-Wansley	1	4.21%	83.58%
7	1-Farley	1	3.39%	86.97%
8	1-Hatch	1	3.39%	90.36%
9	1-McIntosh CC	1	3.39%	93.74%
10	1-Vogtle	1	1.71%	95.45%
11	1-Bowen 1-Scherer	2	1.39%	96.84%
12	1-Bowen 1-Wansley	2	0.95%	97.79%
13	1-Bowen 1-Farley	2	0.76%	98.55%
14	1-Bowen 1-Hatch	2	0.76%	99.31%
15	1-Bowen 1-Vogtle	2	0.39%	99.70%
16	1-Wansley 1-Scherer	2	0.30%	100.00%

Table 2. Unit-out Probabilities (Off-Peak)

Rank	Units Outaged	Number of Units Out	Probability (Rounded)	Sum of Probabilities
1	No Outages	0	28.29%	28.29%
2	1-Bowen	1	17.48%	45.77%
3	1-Scherer	1	7.76%	53.53%
4	1-McIntosh CC	1	6.86%	60.39%
5	1-McDonough CC	1	6.86%	67.25%
6	1-Franklin CC	1	5.94%	73.19%
7	1-Wansley	1	5.39%	78.58%
8	1-Farley	1	2.75%	81.33%
9	1-Hatch	1	2.75%	84.08%
10	1-Bowen 1-Scherer	2	1.93%	86.01%
11	1-Bowen 1-McDonough CC	2	1.71%	87.72%
12	1-Bowen 1-Franklin CC	2	1.48%	89.20%
13	1-Vogtle	1	1.39%	90.59%
14	1-Bowen 1-Wansley	2	1.34%	91.93%
15	1-Bowen 1-McIntosh CC	2	1.18%	93.11%
16	1-Scherer 1-McDonough CC	2	0.76%	93.87%
17	1-Bowen 1-Farley	2	0.69%	94.55%
18	1-Bowen 1-Hatch	2	0.69%	95.24%
19	1-Scherer 1-Franklin CC	2	0.66%	95.90%
20	1-Scherer 1-Wansley	2	0.60%	96.49%
21	1-Wansley 1-McDonough CC	2	0.53%	97.02%
22	1-Scherer 1-McIntosh CC	2	0.52%	97.54%
23	1-Wansley 1-Franklin CC	2	0.46%	98.00%
24	1-Wansley 1-McIntosh CC	2	0.36%	98.36%
25	1-Bowen 1-Vogtle	2	0.35%	98.71%
26	1-Scherer 1-Farley	2	0.30%	99.01%
27	1-Scherer 1-Hatch	2	0.30%	99.32%
28	1-Wansley 1-Farley	2	0.21%	99.53%
29	1-Wansley 1-Hatch	2	0.21%	99.74%
30	1-Scherer 1-Vogtle	2	0.15%	99.89%
31	1-Wansley 1-Vogtle	2	0.11%	100.00%

Table 3. Hydro Schedule Used For 2021 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 2021 Energy Cases
(Fractions of peak Demand)

Average Hourly Percentages of ITS Peak Load for Each Daytype						
Hour	Summer		Winter		Fall/Spring	
Ending	(defined as June1 - Sept 30)		(defined as Dec 1 - Feb 29)		(defined as Mar 1 - May 30 and Oct 1 - Nov 30)	
	SWD	**SWE**	**WWD**	**WWE**	**FWD**	**FWE**
100	0.5592	0.5565	0.5410	0.5459	0.4568	0.4491
200	0.5303	0.5233	0.5365	0.5390	0.4435	0.4325
300	0.5139	0.5014	0.5405	0.5389	0.4397	0.4243
400	0.5120	0.4893	0.5579	0.5457	0.4483	0.4236
500	0.5329	0.4878	0.5982	0.5618	0.4801	0.4320
600	0.5747	0.4928	0.6610	0.5863	0.5371	0.4486
700	0.6001	0.5032	0.6919	0.6137	0.5657	0.4681
800	0.6231	0.5389	0.6822	0.6315	0.5657	0.4900
900	0.6597	0.5894	0.6644	0.6285	0.5659	0.5063
1000	0.7086	0.6441	0.6475	0.6113	0.5708	0.5157
1100	0.7594	0.6983	0.6292	0.5905	0.5757	0.5220
1200	0.8054	0.7485	0.6117	0.5724	0.5816	0.5292
1300	0.8445	0.7896	0.5994	0.5554	0.5905	0.5362
1400	0.8704	0.8199	0.5892	0.5432	0.5973	0.5433
1500	0.8873	0.8418	0.5866	0.5403	0.6042	0.5520
1600	0.8969	0.8558	0.5979	0.5516	0.6131	0.5644
1700	0.8936	0.8582	0.6269	0.5818	0.6217	0.5793
1800	0.8791	0.8458	0.6662	0.6214	0.6287	0.5903
1900	0.8576	0.8202	0.6778	0.6325	0.6327	0.5950
2000	0.8340	0.7939	0.6726	0.6293	0.6323	0.5952
2100	0.7997	0.7625	0.6528	0.6149	0.6112	0.5774
2200	0.7345	0.7047	0.6209	0.5903	0.5685	0.5403
2300	0.6662	0.6428	0.5876	0.5622	0.5221	0.4992
2400	0.6031	0.6009	0.5547	0.5607	0.4809	0.4745

Table 5. Weighting For 2021 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	88	6,521.17129	573,863	466,008	41,008,679
Summer Week End	34	5,950.10636	202,304	435,710	14,814,133
Winter Week Day	66	5,800.38591	382,825	394,739	26,052,783
Winter Week End	25	5,435.80806	135,895	377,713	9,442,824
Fall/Spring Weekday	108	4,700.67351	507,673	359,978	38,877,649
Fall/Spring Weekend	45	4,481.12275	201,651	342,086	15,393,887
Total	366		2,004,211		
	161,428	Total Annual Energy 500/230/115 kV Transformer No-Load Losses (MWh)			
Total Annual Energy Losses	2,165,639				
Total Annual Load	145,589,954				
Energy Loss Factor (B)	**1.4657%**	LF = Loss/(Load + Loss)			

ITS JOINT SUBCOMMITTEE FOR TRANSMISSION PLANNING

2021 ITS LOSS STUDY

APPROVAL PAGE

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[E]

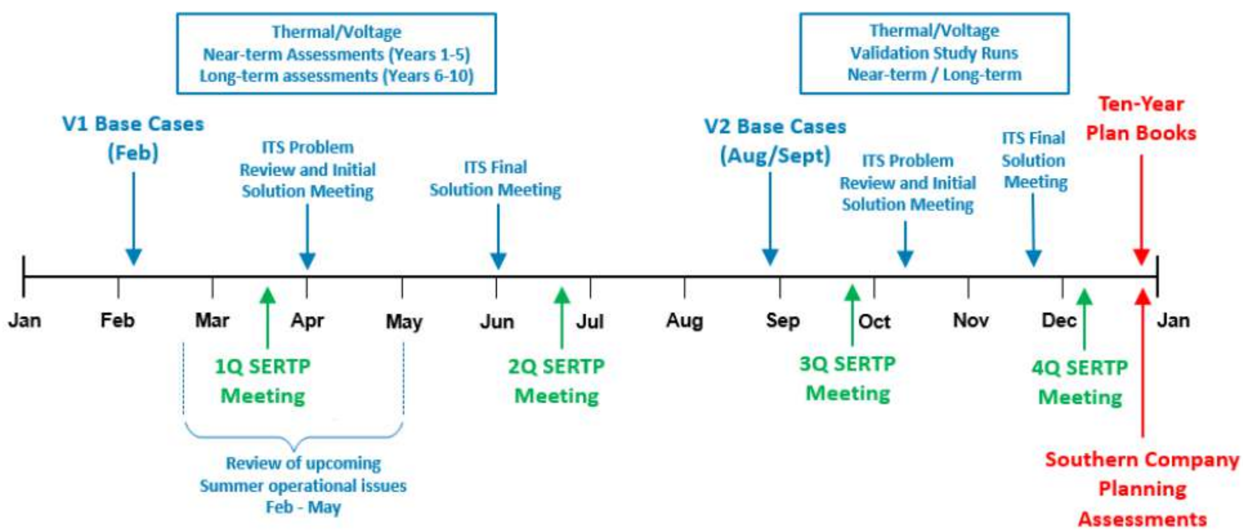
INTERFACE AND INTERCONNECTIONS

[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, 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 (2022-2031). 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

- 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 2020 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 (2021-2030). 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 1/1/2019 through 12/31/2021 within the Georgia Integrated Transmission System.

PUBLIC DISCLOSURE

Point of Receipt	Point of Delivery	Assign Ref	Transmission Provider	Queued Time	Customer	Source	Transmission Service Type	Status	Capacity Requested (MW)	Start Time	Stop Time
[redacted]											

[redacted]

[redacted]

[redacted]

[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 2021.

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 Dominion Energy South Carolina (DESC), 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 (196 MW), TVA (327 MW), Duke (312 MW) and Florida (65 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/woa/docs/SOCO/SOCOdocs/Transmission_Reliability_Margin_Implementation_Document_(TRMID)_v1.3.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 (100 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_CBMID.pdf.

Import Capability

The methodology for calculating import capability on the "northern" interfaces of MISO, TVA, Duke, DESC 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]

OPTIMAL TRANSMISSION SITES FOR GENERATION IN GEORGIA

OPTIMAL GENERATION SITING STUDY

Given that 1) Georgia Power Company exists in a regulated market where the elimination of transmission constraints is a primary focus of transmission planning processes and 2) the net demand (location and magnitude of generation sources and forecasted load) is a key input to the determination of such transmission constraints, the Optimal Generation Siting Study is performed to identify locations where interconnected generation would not exacerbate transmission constraints.

The methodology has changed since the last time this study was performed. Previous studies were done in support of siting Combined Cycle ("CC") units on the system. However, the resulting locations identified by transmission were often in areas that were not suitable for CC technology (no water, rail, or gas pipeline availability, for example). For that reason, the information was seen as providing little value, and the study and associated posting were discontinued. The new methodology identifies potential substation sites that are more suitable in size for renewable projects, specifically solar. Given current solar activity in the state, this methodology provides improved value, and the resulting study is included in the filing.

To determine these optimal generation siting locations, the Optimal Generation Siting study uses the following methodology:

- A load flow model is created with generation injected into a single Integrated Transmission System (ITS) substation bus.
- Next, transmission line contingency analysis (i.e., N-1 and N-G-1 analysis) is performed to determine the generation limit of the substation.
- The previous two steps are repeated for each substation.
- Substations must be able to accommodate a generation injection of 300 MWs minimum to be considered a viable optimal generation site.
- Due to the concentration of solar photovoltaic generating resources in South Georgia and the resulting increase in south-to-north power flow, the selected substations are limited to those in the North Georgia.
- The list is further limited to breakered substations for ease of generator interconnection.

Each year there are new generation, load, and transmission assumptions that will change how power will flow on the transmission system and could impact the resulting optimal sites, so the study will be repeated periodically going forward.

Using the methodology described above the optimal generating siting locations are at the substations listed below:

Optimal ITS Substations for Generation Interconnections

ADAMSVILLE	HARTWELL ENERGY	PORTLAND
ALPHARETTA	HOLLY SPRINGS	POSSUM BRANCH
ASHFORD	JONESBORO	ROOPVILLE
BANKS CROSSING	KLONDIKE	ROSWELL
BAY CREEK	LGE MONROE	STOCKBRIDGE
BETHABARA	MCDONOUGH	SUWANEE
BUZZARD ROOST	MONROE	TRIBUTARY
CARTERSVILLE	MOON ROAD	UNION CITY
CLARKSBORO	OCEE	VILLA RICA
CLARKSTON	OLA	WEST MARIETTA
CORN CRIB	PARKAIRE	WINDER PRIMARY
DOYLE	PONCE DE LEON	
EAST SOCIAL CIRCLE	POND FORK	

[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.

	PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	PLANT ADDITIONS
1	ADAIRSVILLE 115/25 KV CAPACITY PROJECT	Replace existing 115/25 KV banks with 40 MVA 115/25 KV banks.	01-Jun-22	[redacted]
2	AEROTROPOLIS SUBSTATION ADVANCED LAND PURCHASE	Acquire property suitable for future area substation on the west side of Hartsfield-Jackson airport property in the vicinity of the East Point - Mountain View 115kV line.	31-Dec-25	
3	BATTLECREEK CAPACITY INCREASE	Install a new 115/25 kV 40 MVA LTC Bank.	31-Dec-22	
4	BRASELTON AREA CAPACITY INCREASE - HOSCHTON 115/25KV SUBSTATION	Purchase property and construct a new 115/25kV area substation. Install one 115/25kV 40MVA bank.	31-Dec-23	
5	BURKHALTER ROAD 115/12-KV BANK CAPACITY PROJECT	Install a new 115/12kV 25MVA Bank.	01-Dec-25	
6	CARMEL CHURCH 115/25/12KV SUBSTATION PROJECT	Purchase property and construct a new 115/25/12kV area substation. Install one 115/12kV 10.5MVA bank and one 115/25kV 25MVA bank.	31-Dec-25	
7	CHATHAM INDUSTRIAL CAPACITY INCREASE FOR PROJECT LIVE OAK	Install a new 115/25 kV 40 MVA Bank.	31-Mar-22	
8	COAL MOUNTAIN SUBSTATION	Construct 115/12kV area substation on property transferred from PHFFU. Install one 230/25kV 40MVA bank.	01-Jun-22	
9	EATONTON AREA 46 KV - PUTNAM SAWMILL	Purchase property and construct a new 115/12kV area substation. Install one 115/12kV 10.5MVA bank.	31-Dec-24	
10	GODLEY TRACT 2ND BANK ADDITION	Install a new 115/13.8 kV 40MVA Bank.	31-Dec-24	

11	JEFFERSON STREET #3 (GPC OWNED)	Construct new 115kV - six (6) element ring bus substation to serve three (3) customer owned 100MVA 115/34.5kV banks on customer owned property.	01-Sep-22	[redacted]
12	LEWISTON 115/12KV SUBSTATION	Construct 115/12kV area substation on property transferred from PHFFU. Install one 115/12kV 40MVA bank.	01-Dec-25	
13	LILBURN 115/25KV CAPACITY INCREASE	Install a new 115/25 kV 40 MVA LTC Bank.	01-Jun-24	
14	MEDICAL ARTS SUBSTATION PROJECT	Construct 115/13.8kV area substation on property transferred from PHFFU.	31-Dec-26	
15	NORMANDY STREET TIMELY LAND PURCHASE	Acquire 2 acre site in the vicinity of President Street and the Boulevard - Deptford 115kV line in Savannah for future Area Substation.	31-Dec-23	
16	NORTH THOMSON BANK LOADING - OLD WASHINGTON ROAD	Construct 115/25/12kV area substation on property transferred from PHFFU. Install one 115/12kV 10.5MVA bank and one 115/25kV 10.5MVA bank.	01-Dec-24	
17	RICE HOPE 115/25 KV SUBSTATION PROJECT	Construct 115/25kV area substation on property transferred from PHFFU. Install one 115/25kV 50MVA bank.	01-Jun-25	
18	SHUGART FARMS	Construct new 230kV - eight (8) element breaker and a half substation to serve six (6) 60MVA 230/25kV LTC banks on customer owned property. Customer paid for this facility.	01-Sep-22	
19	SOUTH DAHLONEGA SUBSTATION	Construct 115/25kV area substation on property transferred from PHFFU. Install one 115/25kV 25MVA bank.	01-Jun-23	
20	SWITCH WAY SUBSTATION	Construct new 230kV substation with a 60MVA 230/12kV bank on customer owned property.	30-Dec-22	
21	VOYLES ROAD - NEW SUBSTATION	Construct new 115 kV substation with a 50MVA 115/25kV bank on customer owned property.	01-Dec-22	

[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 2021, 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 2019 through 2023. This sample of 27 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.

$$\$/\text{kW} = \frac{\sum \text{(Project Costs in 2021 Dollars)}}{\sum \text{(Delta kW Capacity)}}$$

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 2021 for distribution feeders. The Company extracted data from a GIS mapping system for approximately 2500 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.

$$\$/\text{kW}_{(\text{trunk feeder})} = \frac{\sum \text{(avg. trunk feeder mi. x costs per mi.)}}{\sum \text{(trunk feeder planning capacity limit)}}$$

$$\$/\text{kW}_{(\text{tap line})} = \frac{\sum \text{(avg. tap line mi. x costs per mi.)}}{\sum \text{(tap line planning capacity limit)}}$$

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.

$$\$/\text{kW} = \frac{(\$/\text{kW @ 25 kV} + \$/\text{kW @ less than 25 kV})}{2}$$

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.

$$\textbf{\$/kW = Average} \left(\frac{\boldsymbol{Project\ Cost}}{\boldsymbol{kW\ Growth}}\right)$$

[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) which includes 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

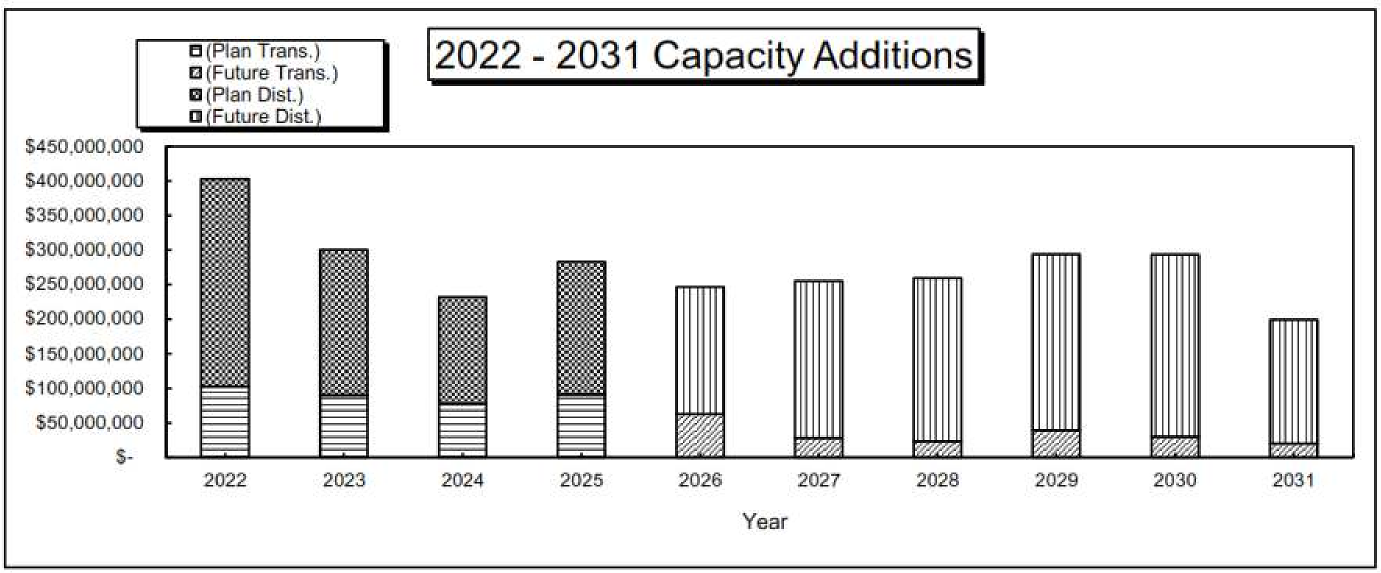
Budget Change Authorization Cost	**Authorized Approval**
Less Than or Equal to $300,000	**Estimator**
Greater than $300,000 & Less than or Equal to $500,000	**Project Manager**
Greater Than $500,000 & Less Than $1,000,000	**TPRT**
Greater Than $1,000,000 & Less Than or Equal to $5,000,000	**TPRT & General Manager**
Greater Than $5,000,000	**TPRT, General Manager, T&D Council, & Vice President**

[G3]

POWER DELIVERY CAPACITY ADDITION EXPANSION PLAN

2022 - 2031 T & D CAPACITY ADDITION EXPANSION PLAN

		NETWORK TRANSMISSION		LOAD SERVING DISTRIBUTION		TOTALS
		(Plan Trans.)	(Future Trans.)	(Plan Dist.)	(Future Dist.)	
1	2022	$ 103,018,676		$ 300,103,172		$ 403,121,848
2	2023	$ 90,077,906		$ 210,358,739		$ 300,436,645
3	2024	$ 78,455,319		$ 153,686,775		$ 232,142,094
4	2025	$ 91,326,534		$ 191,642,746		$ 282,969,280
5	2026		$ 62,772,213		$ 183,809,275	$ 246,581,488
6	2027		$ 28,679,634		$ 226,544,338	$ 255,223,972
7	2028		$ 23,459,897		$ 235,615,058	$ 259,074,955
8	2029		$ 39,310,102		$ 254,523,052	$ 293,833,154
9	2030		$ 29,903,889		$ 263,838,233	$ 293,742,122
10	2031		$ 20,238,864		$ 178,753,740	$ 198,992,604
Total		$ 362,878,435	$ 204,364,600	$ 855,791,432	$1,343,083,695	$2,766,118,162



[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 2019 IRP filing are included in the attached CD. A sample project follows.

SOME INFORMATION IN THE SAMPLE BCA HAS BEEN REDACTED.

THE FLASH DRIVE ATTACHMENT WITH OTHER BCAS AND SUPPORTING DOCUMENTATION HAS BEEN REDACTED.

PUBLIC DISCLOSURE

POWER DELIVERY

Deliver world-class value to every customer, every day, safely.

Transmission Project Review Team

Project Approval Checklist (Version v1.0)

Project Information | Expedited? (Yes or No): No | Date: 2/19/20 | TEAMS ID: **16897**

Project Name: EAST WATKINSVILLE - RUSSELL DAM 230 KV RECONDUCTOR

Project Description: Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor. Replace the OHGW.

Funding Source(s) (PE): 6589

Present Budget:	$0
This Revision:	[redacted]
Increase (Decrease):	
CIAC:	
Cash Required:	
Removals:	

Approval Type (select one)	ITS Treatment (Select all that apply)
(●) New Project	[x] ITS Parity
Existing Project - Revision	[ ] ITS Parity & DSF
( ) Cost Revision	[ ] DSF only
( ) Year Revision	[ ] Non-ITS
( ) Scope Change	[ ] <$100,000
( ) Cancelled Project	[ ] For Information Only
( ) Distribution Only	

Estimate Review

Yes	No or N/A	
[x]	[ ]	"Cost by Units" analysis
[x]	[ ]	Crew Support Estimated
[ ]	[x]	Major Equipment (qty, estimated)
[ ]	[x]	Mobile estimated
[x]	[ ]	Schedule/Budget Spread Rvw

Checklist

Yes	No or N/A	
[x]	[ ]	BCA Documents
[x]	[ ]	PE Spread
[x]	[ ]	WAR/PCD/TIN
[ ]	[x]	Land Item Required
[ ]	[x]	Telecom and SIA Impact
[ ]	[x]	New Business
[ ]	[x]	CIAC
[ ]	[x]	Distribution Item ________
[ ]	[x]	Mobile Required
[x]	[ ]	Schedule Review
[ ]	[x]	Revision Justification
[ ]	[x]	Generation Interconnection Agreement

Yes	No or N/A	
[x]	[ ]	Solution Team
[x]	[ ]	Scoping Meeting
[x]	[ ]	Project Plan
[x]	[ ]	Operations Review
[x]	[ ]	TP East Review
[x]	[ ]	TEAMS - Budget Class Code
[x]	[ ]	TEAMS - Disposition Code

Compliance Impact

Yes	No or N/A	
[ ]	[x]	Security
[ ]	[x]	PRC
[ ]	[x]	Vegetation
[ ]	[x]	Other ________

Comments:

Project Contacts

Project Originator: [redacted] Project Manager: [redacted]

Date: 2/19/2020 Distribution Project Manager: ________

Project ID: **16897**

Originator: [redacted]

Department: TRANSMISSION PLANNING - EAST

Project Manager: [redacted]

Project Name: **EAST WATKINSVILLE - RUSSELL DAM 230 KV RECONDUCTOR**

Project Need Date: 06/01/2023

Estimated Start Date: [redacted]

Latest Required Date: [redacted]

PE Number: 6589

Present Budget:
This Revision:
Increase(Decrease): [redacted]

Category: TRANSMISSION

Type: Capital

Region: NORTHEAST

Area: CENTRAL-ATHENS

Approvals and Dates:

Project Manager
Lead Project Manager
Gen. Mgr. System Performance
Budget Coordinator
[redacted]

TPRT Chair
Financial Supervisor
Power Delivery SVP
[redacted]

Project Description:

BCA Approved 3/10/20
Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor. Replace the OHGW.

Supporting Statement
Industry consensus is SD Conductor has reached the end of its service life. This type of conductor is no longer manufactured and there is very little remaining in stock with which to make repairs. Also, a capacity increase is necessary to accommodate future import obligations across the VACAR interface.

SW 143129 E Watkinsvle(1) - STR 13 COR - 1351.5 ACSR-SD
STR 13 COR - SW 101543 Lexington(78)
SW 101531 Lexington(79) - SW 000139 Russell Dam(214)

PE Item/ Project Item No.	Facility Name / Fac Reqd Area Location / Project Description	Ownr	Plt Addn Engr. Loc
03	**EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV**		[redacted]
1689707	12/31/2020	GPCO	
	Section 1: Russell Dam - Str. #185. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (6.1 miles). Replace both OHGWs with 3/8" HS steel.		
04	**EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV**		[redacted]
1689708	06/01/2021	GPCO	
	Section 2: Str. #185 - Str. #150. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (8.1 miles). Replace both OHGWs with 3/8" HS steel.		

PE Item/ Project Item No.	Facility Name / Fac Reqd Area Location / Project Description	Ownr	Plt Addn Engr. Loc
05	**EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV**		[redacted]
1689709	12/31/2021	GPCO	
	Section 3: Str. #150 - Str. #126. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (5.8 miles). Replace both OHGWs with 3/8" HS steel.		
06	**EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV**		[redacted]
1689710	06/01/2022	GPCO	
	Section 4: Str. #126 - Lexington Substation. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (10.5 miles). Replace both OHGWs with 3/8" HS steel.		
07	**EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV**		[redacted]
1689711	12/31/2022	GPCO	
	Section 5: Lexington Substation - Str. #52. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (6.3 miles). Replace both OHGWs with 3/8" HS steel.		
08	**EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV**		[redacted]
1689712	06/01/2023	GPCO	
	Section 6: Str. #52 - East Watkinsville. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (10.7 miles). Replace both OHGWs with 3/8" HS steel.		
09	**LEXINGTON**		**$0**
1689713	06/01/2022	GTC	
	GTC - replace 1600A switches 101531 and 101543 with 3000A switches.		
10	**RUSSELL DAM (USA)**		**$0**
1689714	06/01/2022	SEPA	01-147
	US Army Corps of Engineers - Replace 1590 AAC jumpers from the East Watkinsville 230 kV line (COE calls it Line #1) to the buswork between PCB's 138 and 148.		

Items

Pe Item :	03	04	05	06	07	08	09	10
Proj Item :	1689707	1689708	1689709	1689710	1689711	1689712	1689713	1689714
Plt Add :	[redacted]							
(CIAC) :								
Net Add :								
(Plt Tfr):								
Removal :								
(CIRC) :								
(Salvage):								
Cash Rqd :								
OCR :								

Pe Item :	PE
Proj Item :	Totals
Plt Add :	[redacted]
(CIAC) :	
Net Add :	
(Plt Tfr):	
Removal :	
(CIRC) :	
(Salvage):	
Cash Rqd :	
OCR :	

Item Expenditures by Year

PE Item : 03
Proj Item : 1689707

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals
Plt Add :	[redacted]						
(CIAC) :							
Net Add :							
(Plt Tfr):							
Removal :							
(CIRC) :							
(Salvage):							
Cash Rqd :							
OCR :							

PE Item : 04
Proj Item : 1689708

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals
Plt Add :	[redacted]						
(CIAC) :							
Net Add :							
(Plt Tfr):							
Removal :							
(CIRC) :							
(Salvage):							
Cash Rqd :							
OCR :							

PE Item : 05
Proj Item : 1689709

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals
Plt Add :	[redacted]						
(CIAC) :							
Net Add :							
(Plt Tfr):							
Removal :							
(CIRC) :							
(Salvage):							
Cash Rqd :							
OCR :							

PE Item : 06
Proj Item : 1689710

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals
Plt Add :	[redacted]						
(CIAC) :							
Net Add :							
(Plt Tfr):							
Removal :							
(CIRC) :							
(Salvage):							
Cash Rqd :							
OCR :							

Project ID: **16897**

PE Item : 07
Proj Item : 1689711

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals

Plt Add :
(CIAC) :
Net Add :
(Plt Tfr):
Removal :
(CIRC) :
(Salvage):
Cash Rqd :
OCR :
[redacted]

PE Item : 08
Proj Item : 1689712

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals

Plt Add :
(CIAC) :
Net Add :
(Plt Tfr):
Removal :
(CIRC) :
(Salvage):
Cash Rqd :
OCR :
[redacted]

PE Item : 09
Proj Item : 1689713

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals

Plt Add :
(CIAC) :
Net Add :
(Plt Tfr):
Removal :
(CIRC) :
(Salvage):
Cash Rqd :
OCR :
[redacted]

PE Item : 10
Proj Item : 1689714

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals

Plt Add :
(CIAC) :
Net Add :
(Plt Tfr):
Removal :
(CIRC) :
(Salvage):
Cash Rqd :
OCR :
[redacted]

Project ID: **16897**

Grand Totals

Budget Yr :	2020	2021	2022	2023	2024	Extended	Totals
Plt Add :	[redacted]						
(CIAC) :							
Net Add :							
(Plt Tfr):							
Removal :							
(CIRC) :							
(Salvage):							
Cash Rqd :							
OCR :							

** End of Report **

EAST WATKINSVILLE – RUSSELL DAM 230 KV RECONDUCTOR
TEAMS 16897
Project Need Date June 1, 2023
Documentation Date February 1, 2020

I. Executive Summary

The 48.3-mile East Watkinsville – Russell Dam 230 kV line was constructed with 1351 ACSR Martin-SD (Self-Damping) conductor. Industry consensus is that SD Conductor has reached the end of its service life. This type of conductor is no longer manufactured and there is very little remaining in stock with which to make repairs. Georgia Power currently has a program to replace all SD conductor on its system.

Also, Transmission Planning's 2019 Northern Interface Study identified this line as a limit to import capability by 203. Loading is also projected to increase if existing baseload coal units are retired. This deficiency can be alleviated at relatively low incremental cost by utilizing 1351 ACCR conductor rather than standard 1351 ACSR conductor. The line's capacity will increase by roughly 53%. The ITS Interface Working Group has recommended this approach.

Construction will be spread over six consecutive Spring and Fall seasons beginning Fall 2020.

II. Compliance Statement

This project addresses problems associated with NERC Category P1/P3 events. These problems were identified as part of Southern Company's transmission planning process in compliance with NERC Standards TPL-001-4.

III. Background and Problem Description

<u>Problem 1 – 230 kV Maintenance Issue</u>

The 48.3-mile East Watkinsville – Russell Dam 230 kV line was constructed in 1982 with 1351 ACSR Martin-SD (Self-Damping) conductor. Industry consensus is that SD Conductor has reached the end of its service life. This type of conductor is no longer manufactured and there is very little remaining in stock with which to make repairs. Georgia Power currently has a program to replace all SD conductor on its system (see Attachment A, "TD Council - Blanket Funding Request 2016_SD Conductor"). Following is a write up from [redacted] Transmission Line Design Supervisor:

> In my capacity as a Transmission Line Design Supv for 20+ years, I have noted numerous failures on existing Transmission Lines constructed with Self Damping conductor. I am most familiar with the 230kv lines around the Rome, GA and Athens, GA areas. All of these lines were constructed in the 1970's. In assisting and researching the root cause of these abnormal failures, I contacted several industry acquaintances who I know through Industry involvement. [redacted] is a Principal with Utility Consultants and is a recognized Conductor Expert in the utility industry. [redacted] is the Principal Engineer for Southwire Corp who is our Alliance Partner for conductors. Both of these gentlemen recognized the SD product as a popular utility conductor in the 1970's used across the United States. Both also commented that their knowledge of the product would indicate a typical life expectancy of 30 years or less, depending on the vibration activity of the product. They relayed the normal wear mode for the conductor in 2 areas. The nature of Self Damping conductor comes from a specific manufacturing process that allows the steel stranded core of the conductor to be free and disconnected from the outer aluminum

strands of the ACSR. During vibration instances, the steel core can actively move within the aluminum strands. This active movement within the conductor allows for vibration energy to be dissipated and typical aeolian vibration damage to be reduced significantly.
1- Since the conductor and core are actively moving independently of each other, this does cause wear over time within the conductor. Most typically, the rust resistant coating of the steel strands wears away, leading to core corrosion and core failure.
2- The core strands moving within the aluminum strands can cause fretting of the aluminum into a powder which actually seals the conductor body. The conductor will actually hold water from rain and condensation. This excess moisture builds up in the conductor also leads to core corrosion and failure.
My knowledge of failures within the Georgia Power system and across the other Op Co's, is consistent with [redacted] and [redacted] opinions. Core corrosion and aluminum fretting have all been observed. An instance of SD Conductor in the Gulf Power area was reported that when the conductor was cut for repair, water literally poured from the core.
For the reasons stated above, it is my opinion that the SD Conductor installed in the Southern Co System, vintage 1970's, be considered at the end of life and should be replaced as soon as practical.

This line has already experienced several failures for which repairs have had to be made, according to the TMC.

In addition, even if the 1351 ACSR SD conductor is replaced with 1351 ACSR standard conductor, it is estimated that 39% of the existing structures will need to be raised or replaced to meet current NESC codes and standards. These structures are in generally good condition, but they are relatively short.

<u>Problem 2 – Transmission Planning Interface Import Capability Issue</u>

Transmission Planning has identified a need for increasing the capacity of the line. Import capability from the VACAR utilities is projected to be insufficient to meet expected firm transmission service obligations along with required Capacity Benefit Margin (CBM) and Transmission Reserve Margin (TRM) by 2023 (see Attachment B, "2019 Interface Transfer Capability Assessment Summary - v2C"). Possible future baseload coal unit retirements will further increase loading on this circuit. To address this deficiency, the ITS Interface Working Group (IWG) made a recommendation (see Attachment C, "IWG_Final Meeting Report_June-2019") to change the project scope, which was originally to reconductor the line with standard (non-SD) 1351 ACSR Martin conductor, to 1351 ACCR Martin conductor. ACSR would provide no capacity increase; ACCR will increase the capacity by roughly 53% with a cost increase of 11% according to preliminary engineering estimates (see Attachment D, "0739_2 Estimate Basis 050719".

IV. Study Assumptions

List the types of cases, dispatches, years, sensitivities and load levels studied, and any changes/updates/corrections made to them.

- Series 2019, Version 2 Summer Peak, Summer Daylight Shoulder, and Summer Dusk Shoulder cases were used for the interface analysis.
- Study years: 2020-2029

V. Discussion of Alternatives

Because of the past and potential future failures of the self-damping conductor, there is no viable alternative other than to reconductor/rebuild the entire line. The discussion of alternatives thus centers around which type of conductor to use. When Transmission Line Support originally scoped the project, standard 1351 ACSR Martin conductor was specified. After Transmission Planning became involved, several other conductor types were considered. Preliminary engineering evaluated the following alternatives:

Conductor Type	1351 ACSR	1351-T13 ACCR	1622-T13 ACCR/TW	1351 ACSS	(2) 795 ACSR
Ampacity	1456	2229	2495	2248	2092
% Increase in Ampacity	0%	53%	71%	54%	44%
Structure Raised	29	24	27	49	15
Structures Replaced	55	21	53	80	164
% Raised or Replaced	39%	21%	37%	60%	83%
Estimated Cost*	[redacted]				
Cost % of Base					

*Excluding land costs and overheads

ACSR or ACSS vs. ACCR: ACCR ceramic core conductor is far more expensive ([redacted] vs. [redacted] for ACSR and [redacted] for ACSS), but it is lighter (1.46 lbs./ft. vs 1.74 lbs./ft.) which means a lower number of structures need to be replaced or raised.

- The 1351 ACSR option solves the maintenance issue but does nothing for the import capability issue. Because of this and the fact that other options do solve the issue at a small incremental cost, 1351 ACSR was not considered, but it provides a basis for comparison.

- The 1351 ACCR option requires some specialized equipment to install and maintain, but its low weight and consequent reduction in structure replacements make this option cost competitive.

- The 1622 ACCR/TW option provide more capacity increase than is needed, and costs more than 1351 ACCR.

- The 1351 ACSS option, on paper, provides approximately the same capacity increase for approximately the same cost, but there is more uncertainty about the cost, with 87 more structures needing raising or replacement, than there is with the ACCR options, since wire costs are a known quantity. Also, because of the additional structures, the timeline would be extended (128 estimated crew weeks for structures against 52 weeks for ACCR), which would make it more difficult to meet the need date. In addition, ACSS (like ACSR-SD) is more challenging to repair in instances where the core breaks, because it contracts and slips along the conductor strands. The core then has to be retrieved and additional wire cut out.

- The (2) 795 ACSR option is the most expensive because its added weight requires replacement of most of the structures. The 44% capacity increase, already not as good as that of ACCR or ACSS, is actually less than it appears, because the addition of a second conductor per phase greatly decreases the line's impedance. Thus, additional flow on the line uses up some of the increased capacity.

For these reasons. The 1351 ACCR option was chosen. Subsequent engineering estimates for the Preferred Plan total [redacted]

The Georgia Control Center has engaged with SEPA, the power marketer for Russell Dam, to develop a mutually acceptable outage schedule, shown below. SEPA desires that the line to be in service as much as possible in Summer and Winter peak seasons:

From	To	Distance	Duration (2 Weeks/Mile)	Season/Year
STR #214/Russell Dam	STR #185	6.1 Miles	[redacted]	Fall 2020
STR #185	STR #150	8.1 Miles		Spring 2021
STR #150	STR #126	5.8 Miles		Fall 2021
STR #126	STR #79/Lexington	10.5 Miles		Spring 2022
STR #78/Lex	STR #51	6.3 Miles		Fall 2022
STR #51	STR #1/E Watkinsville	10.7 Miles		Spring 2023

VI. Conclusion and Recommendations

Reconductoring the line with 1351-T13 ACCR conductor sagged for 200°C operation is the recommended alternative. The 53% capacity increase easily solves the identified import capability limitation and allows for future increased loading due to possible future unit retirements.

VI. ATTACHMENTS

- Attachment A: TD Council - Blanket Funding Request 2016_SD Conductor Presentation
- Attachment B: 2019 Interface Transfer Capability Assessment Summary - v2C
- Attachment C: IWG_Final Meeting Report_June-2019
- Attachment D: 0739_2 Estimate Basis 050719

CSO

Customer Service & Operations

Deliver world-class value to every customer every day

Self Dampening Conductor Replacement PE
PE 6322

[redacted]

Sponsor: [redacted] **Transmission Maintenance GM**

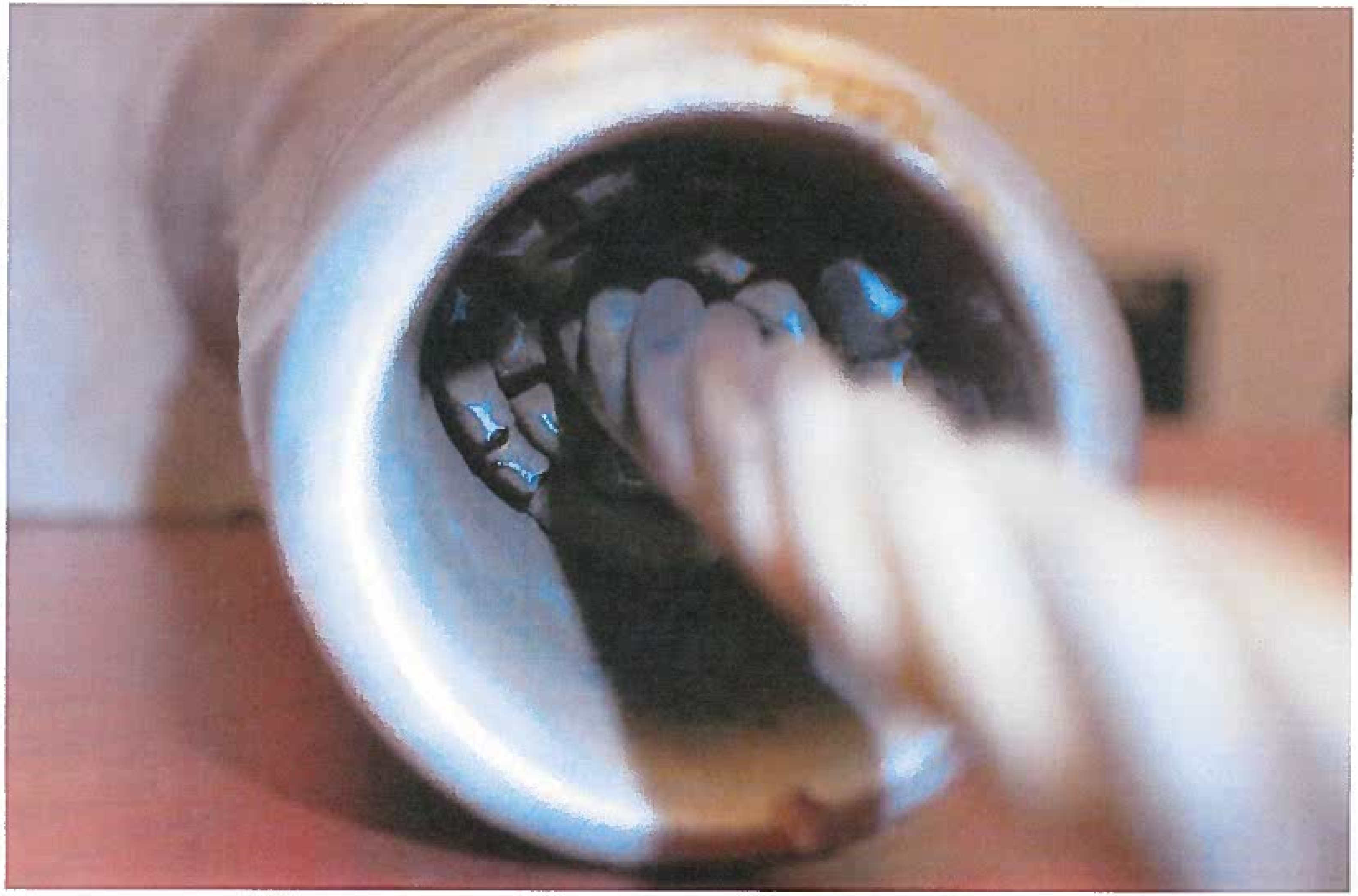
07/01/2016

GEORGIA POWER

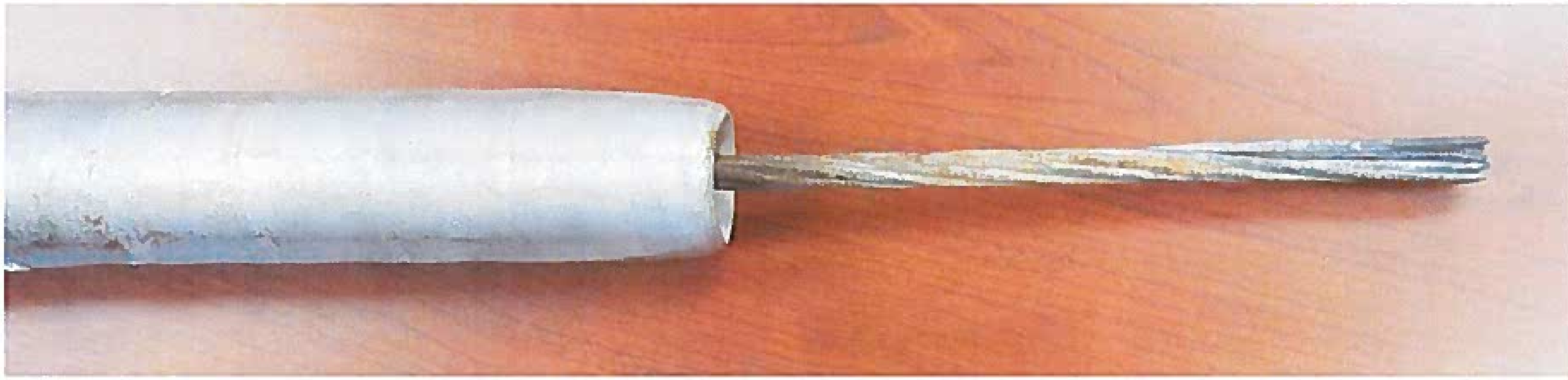
A SOUTHERN COMPANY

Situation

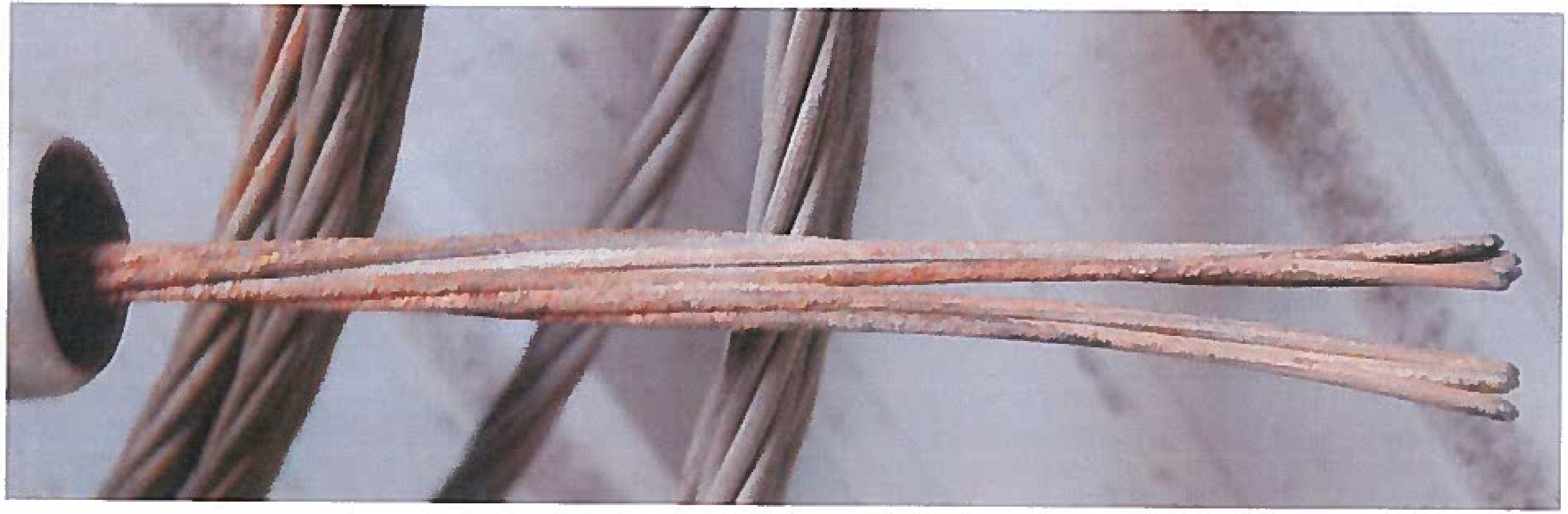
East Dalton -Loopers Farm 115kV



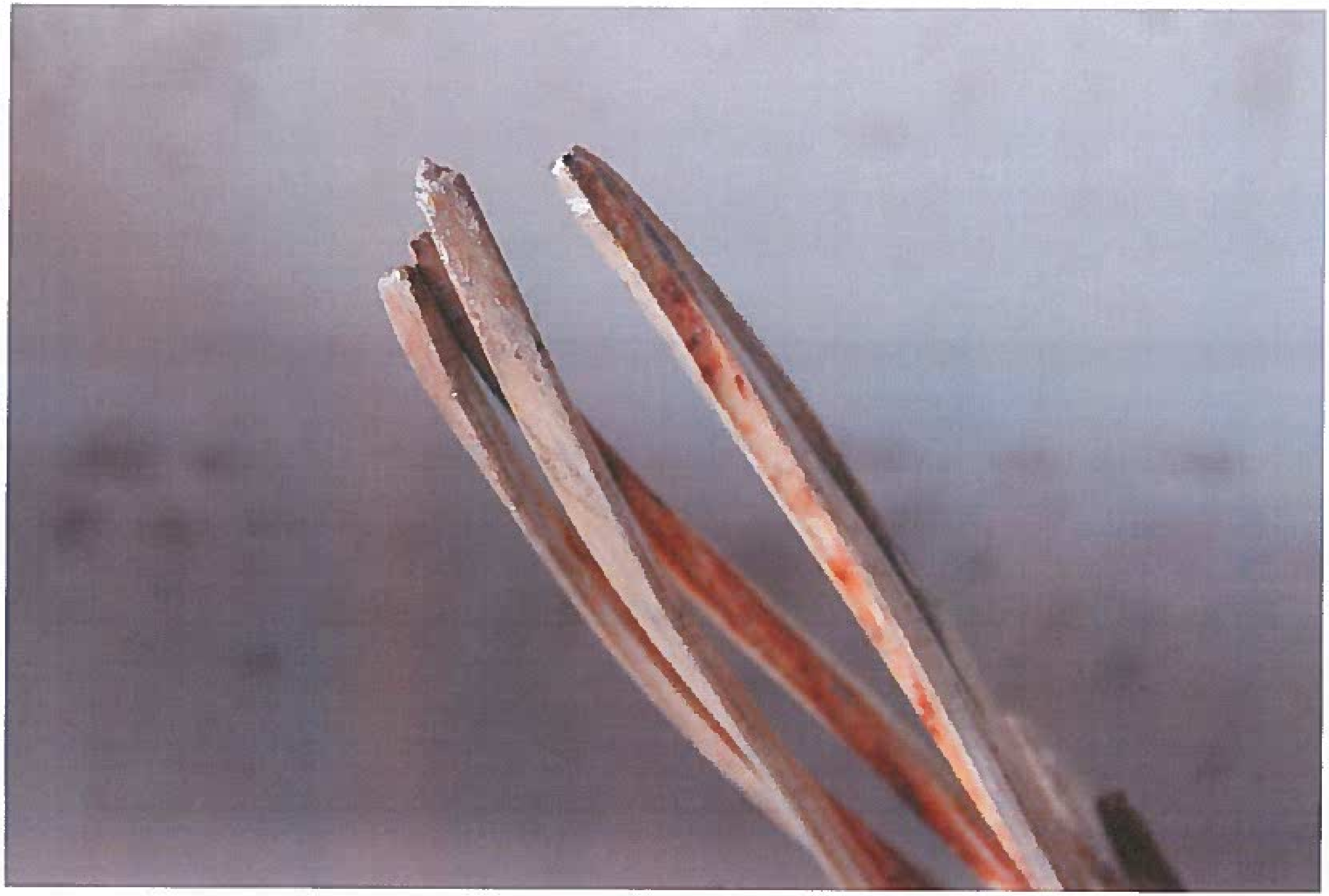
East Dalton -Loopers Farm 115kV



Eatonton – Wallace Dam 230kV



Eatonton – Wallace Dam 230kV



Eatonton – Wallace Dam 230kV

Lines with Self Dampening Conductor

Line Name	Year Built	Miles
ANTHONY SHOALS - RUSSELL DAM (USA) 230 KV	1983	2
BREMEN - SEWELL CREEK 230 KV	1977	19
CEDARTOWN - HAMMOND 230 KV	1978	18
CEDARTOWN - SEWELL CREEK 230 KV	1977	4
CENTER PRIMARY - SOUTH HALL 230 KV	1981	29
DAWSON CROSSING - MCGRAU FORD 230 KV	2002	15
EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	1983	48
EATONTON PRIMARY #2 - WALLACE DAM 230 KV	1979	16
KIA MOTORS - PITTMAN ROAD 115 KV	2007	4
MCMANUS - WEST BRUNSWICK 230 KV	1972	6
NORTH AWRF - SHOAL CREEK 115 KV	1999	2
WADLEY PRIMARY - WAYNESBORO PRIMARY 230 KV	1979	26
WAYNESBORO PRIMARY - WILSON 230 KV	1979	23
Grand Total		211

Scope Explanation

- Identified projects
  - 230kV is the majority of the line mileage (205 Miles)
  - Majority of conductor is older than 1980 (111 Miles)
- Increase Reliability
  - Industry consensus is SD Conductor has reached the end of it service life.
  - Very little remaining in stock with which to make repairs
  - No longer manufactured

Request

- We are requesting the T&D council to approve a total increase of $[redacted] over next 5 years

- Project Cost

	2017	2018	2019	2020	2021	Totals
Proposed	[redacted]					

Southern Company Services
Transmission Planning

Interface Transfer Capability Assessment Summary

Version 2C
September 2019

Interface Transfer Capability Assessments[1]

The transfer capability assessments are used to identify transmission facilities that may potentially limit Southern Companies' 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. This report provides a summary of each interfaces transfer capability limitations.

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 taken into account in the same manner as the Northern Interface.

[1] See Appendix E – Transfer Capability Assessment Descriptions

Executive Summary

Transfer Analysis Results

NIS Results

Full description of NIS assessment results located in the Northern Interface section of this report.

- Exports
    - No constraints identified
- Imports
    - Bio – Avalon 115 kV TL (DUKE);
        - Bio – Airline 1 115 kV; Airline 2 – Pooles Creek – N. Lavonia – TNS Junction South 115 kV;
        - [redacted]
        - Project: Rebuild 20.5 miles of 636 ACSR/795ACSR with 1351 ACSR.
    - Bio – Center 230 kV TL (Simultaneous, Duke)
        - Working with East on solution.
    - Russell Dam – E. Watkinsville 230 kV TL (Simultaneous)
        - Reconductor has been moved up to 2023, which would relieve overload.
    - Goshen – Clark Rd – Greens Cut – Waynesboro115 kV line (DESC)
        - TBD

FIS Results

Full description of FIS assessment results located in the Florida Interface section of this report.

- Exports
    - Pine Grove Primary – West Valdosta 230kV
        - Due to addition of MEAG load
    - Adel 5 – North Tifton 230kV
        - Due to addition of MEAG load
- Imports
    - No constraints identified

Modeling Assumptions Summary

Assumptions for NIS

Full description of NIS modeling assumptions found in Appendix A of this report.

- Added Transfers:
  - Exports
    - [redacted]
  - Imports
    - [redacted]

Assumptions for Gulf

Full description of GIS modeling assumptions found in Appendix A of this report.

- Added Transfers:
  - Exports
    - [redacted]

Assumptions for FIS

Full description of FIS modeling assumptions found in Appendix A of this report.

- Added Transfers:
  - Exports
    - [redacted]

- [redacted]

Assumptions for MISO

- LAGN to PJM transfer modeled in 2020-2022 at 895 MWs
- LAGN to PJM transfer modeled in 2022-2029 at 600 MWs

2019 v2C Transfer Assessment Results

Northern Interface – Duke Imports

☒ Non-Simultaneous Import	☐Simultaneous Import									
Line/Substation Name	Airline 2 – Pooles Creek - N Lavonia - TNS JS 115 KV lines							**Case type**	**Unit Out**	**TDF %**
Contingency	[redacted]							S	JAS	2.11
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element										
Op. Guide	Open Avalon - Gumlog 115kV TL								**Dynamp Time**	16 min ('24)
Project	Rebuild 20.5 miles of 636 ACSR/795ACSR with 1351 ACSR (part of NEC study)								**Cost**	[redacted]
Comments	*-Project stripped from Cases (currently timed for Summer 2024) Discussions ongoing with TP East on project timing.									

Northern Interface – Simultaneous Imports

☐ Non-Simultaneous Import				☒ Simultaneous Import						
Line/Substation Name	Bio – Vanna 230 kV line							Case type	Unit Out	TDF %
Contingency	[redacted]							S	JAS	3.21
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element	100⁰ 1-795 ACSR Drake conductor									
Op. Guide	[redacted]								Dynamp Time	20 min ('24)
Project	Rebuild 8.0 miles of 100⁰C 1-795 ACSR Drake with 2-795 ACSR 230kV transmission line (Being determined as part of NEC study)								Cost	
Comments	53 minutes of dynamp time in 2021									

☐ Non-Simultaneous Import				☒ Simultaneous Import						
Line/Substation Name	R_Vanna – New Haven 230kv line							Case type	Unit Out	TDF %
Contingency	[redacted]							S	JAS	3.07
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element	100⁰ 1-795 ACSR Drake conductor									
Op. Guide	[redacted]								Dynamp Time	30+ min ('24)
Project	Being determined as part of NEC study								Cost	
Comments										

Northern Interface – Simultaneous Imports

☐ Non-Simultaneous Export ☒Simultaneous Import										
Line/Substation Name	Russell Dam – Lexington 230 kV line							Case type	Unit Out	TDF %
Contingency	[redacted]							S	JAS	4.71
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element	1590 AAC Jumpers (596 MVA) and 100º 1-1351 ASCR Martin conductor (602 MVA)									
Op. Guide									Dynamp Time	-
Project	Reconductor 31.3 miles with 200°C 1-1351-T13 ACCR								Cost	
Comments	*-Project stripped from Cases (currently timed for Summer 2023)									

☐ Non-Simultaneous Export ☒Simultaneous Import										
Line/Substation Name	Lexington – R_E Watkinsville 230 kV line							Case type	Unit Out	TDF %
Contingency	[redacted]							S	JAS	4.67
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element	1590 AAC Jumpers (596 MVA) and 100º 1-1351 ASCR Martin conductor (602 MVA)									
Op. Guide									Dynamp Time	-
Project	Reconductor 17.1 miles with 200°C 1-1351-T13 ACCR								Cost	
Comments	*-Project stripped from Cases (currently timed for Summer 2025) The new schedule has this project timed to be in service in 2023 (pe [redacted]									

Interface Transfer Capability Assessment | 2019 – v2C

Northern Interface – Simultaneous Imports

☐ Non-Simultaneous Export	☒ Simultaneous Import									
Line/Substation Name	South Hall - Candler 230 kV line							**Case type**	**Unit Out**	**TDF %**
Contingency	[redacted]							S	JAS/MCD6	5.42
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element	100 1033.5 ACSR Curlew 54/7 (509 MVA)									
Op. Guide	N/A								**Dynamp Time**	-
Project	Being determined as part of NEC study								**Cost**	
Comments										

Northern Interface – DESC Imports

☒ Non-Simultaneous Import							☐Simultaneous Import			
Line/Substation Name	Goshen – Clark Rd – Greens Cut – Waynesboro115 kV line							Case type	Unit Out	TDF %
Contingency	[redacted]							H	HCH1	2.14
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Loading (%) 2019 v1C	[redacted]									
Loading (%)										
FCITC										
Limiting Element	100C 336.4 26/7 ACSR Linnet COND									
Op. Guide	-								Dynamp Time	5 min ('21)
Project	Waynesboro 230/115kV Autobank Addition (per TP-East v2C report)								Cost	[redacted]
Comments	Vogtle 1 was advanced to summer of 2021. Wadley 500/230 kV transformer comes in service later in 2021 causing a reduction in loading.									

Florida Interface – Exports

Simultaneous Export										
Line/Substation Name	Pine Grove Primary – West Valdosta 230kV									
Worst Segment	Pine Grove Primary – West Valdosta 230kV (~10 miles)							**Worst Season**	**Unit Out**	**Avg TDF %**
Contingency	[redacted]							S	HCH1	6.27%
Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Loading (%) 2019 v2C Base	[redacted]									
Loading (%) 2019 v2C w/o Adel 5 Load										
Limiting Element	100C 1-1033.5 ACSR Curlew 54/7 (Rating - 509 MVA). Followed by 1200 A switches at Pine Grove (Rating - 539 MVA).									
Op. Guide	N/A								**Dynamp Time**	~30 Min (2021)
Project	N/A								**Cost**	N/A
Comments	• 230MW Load added at Adel 5 in Version 2 cases									

Florida Interface – Exports

Simultaneous Export										
Line/Substation Name	Adel 5 – North Tifton 230kV									
Worst Segment	Adel 5 – North Tifton 230kV (~30.3 miles)							**Worst Season**	**Unit Out**	**Avg TDF %**
Contingency	[redacted]							H	HOPK	3.35%
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Loading (%) 2019 v2C	[redacted]									
Loading (%) 2019 v2C w/o Adel 5 Load										
Limiting Element	100C 1-1033.5 ACSR Curlew 54/7 (Rating - 509 MVA).									
Op. Guide	N/A								**Dynamp Time**	~15 Min (2025)
Project	N/A								**Cost**	N/A
Comments	• 230MW Load added at Adel 5 in Version 2 cases									

Appendix A – Modeled Firm Commitments

Assumptions & Criteria

The transfer capability assessments are performed utilizing models that contain the most up-to-date assumptions for the SBAA at the time of the study. These assumptions include the most current:

- Generation dispatch, including but not limited to long-term planned outages, additions, and retirements.
- Transmission system topology, including but not limited to long-term planned Transmission outages, additions, and retirements.
- System Demand.
- Approved and projected Transmission uses.
- Parallel path (loop flow) adjustments.

For powerflow modeling data external to the SBAA, Southern Companies participates in the SERC Long Term Study Group ("LTSG") and ERAG Multiregional Modeling Working Group ("MMWG") model development processes. Models developed through these processes are utilized as a foundation for the external powerflow modeling in these transfer capability assessments. The LTSG and MMWG processes annually develop powerflow cases that incorporate system topology, facility ratings, generation dispatch, system demands (load forecasts), and transmission system uses as provided by participating transmission owners. The interchange schedules included in these models are coordinated to reflect forecasted transmission system uses, enabling parallel path (loop flow) impacts to be considered in these assessments. In addition, adjustments to areas external to the SBAA may be performed based upon potential impacts to assessment results, the availability of updated modeling data, and the timing of when each assessment is performed.

Base Case Models	2019 Series V2C: 2020-2029 Summer Peak, Summer Shoulder (Dusk & Daylight)		
Software	Siemens PTI PSS/E 33.10.0 and PTI MUST 12		
Modeled Firm Commitments	See Appendix A	**Reliability Margins**	See Appendix B
ITS Allocation Factors	See Appendix C	**Unit Outs**	See Appendix D

Appendix A – Modeled Firm Commitments

<u>Northern Interface Transfer Capability Modeled Firm Commitments</u>

OASIS #	Source	Sink	MW	Start Date	Stop Date	Modeled in Base Case?	Added to Interface Case	Rollover Modeled beyond Stop Date	Notes
[redacted]									

** [redacted] not modeled in any of the base or interface cases. An annual undesignated screen is performed, per the Southern Company Business Practice, to determine impacts of any undesignated reservations upon the SBAA transmission system. If impacts are found, the requestor must designate, reduce, or withdraw the reservation.

Florida Interface Transfer Capability Modeled Firm Commitments

OASIS #	Source	Sink	MW	Start Date	Stop Date	Modeled in Base Case?	Added to Interface Case	Rollover Modeled beyond Stop Date	Notes
[redacted]									

Appendix B – Reliability Margins

Capacity Benefit Margin (CBM) – effective 3-15-2019

Interface	Amount[2]
Duke	[redacted]
Florida	
MISO	
SCEG	
SCPSA	
TVA	
Total	

Transmission Reliability Margin (TRM) – effective 6-1-2019

Interface	Amount[3]
Duke	[redacted]
Florida	
MISO	
SCEG	
SCPSA	
TVA	
Total	

ATTACHMENT C

Final Meeting Report

For the June 2019, ITS Interface Working Group Meeting

ATTENDEES

- Southern: [redacted]
- GTC [redacted]
- MEAG: [redacted]
- Dalton:

PAST MEETING REPORTS

May meeting report was provided on 5/15/19.

- The IWG will provide comments by COB May 17.
- The May Meeting report was approved

PAST ACTION ITEMS

- TRM Study Results
  - The IWG members were to review and approve the new values.
  - GTC will provide comments by COB May 17. Finalized TRM values will be presented to the JSTP on 5/21/2019.
  - Update: The IWG reached consensus via email on the new TRM values. The values were submitted to and recommended for approval by the JSTP in May. The TRM values were approved at the May Joint Committee meeting.
- 2020 Allocations
  - Nextera desires to have Gulf & Florida modeled as one interface (scenario 3). For the foreseeable future, Gulf Power is a separate BA from SBAA and Florida, but the generation is provided by the SBAA generators (scenario 1). The methodology will be discussed for changes on the 2021 Allocations calculations.
  - Dalton requests that tie lines associated with Loopers Farm be shown as non-ITS tie lines. This request would make the tie lines 100% Dalton allocations out of Loopers Farm. This change may require a change in methodology and study method.
  - Update: GTC will make a presentation to Dalton prior to the July IWG meeting, explaining the role of Loopers Farm in the ITS Allocation Factor Calculation.
- Allocations Scripting Update
  - [redacted] will post the script on the server for input.
  - Update: SOCO will investigate the python script
- Northeast Corridor Study – Phase 2 study scoping
  - SOCO presented the 2019 Interface Study which contains the problem statements for the Northeast Corridor Study. IWG will review and provide feedback.
  - SOCO presented the NEC study scope document. IWG will review and provide feedback.

Final Meeting Report

For the June 2019, ITS Interface Working Group Meeting

DISCUSSION ITEMS

- Northeast Corridor Study
  - SOCO discussed results of the study with the East Watkinsville – Russell Dam 230 kV Line reconductored with 1351 ACCR.
  - IWG agrees to the reconductor of the East Watkinsville – Russell Dam 230 kV Line using 1351 ACCR at 200C operation with a need date of 12/1/2021. GPC will prepare project documentation for submission to the ITS.
  - Study will continue to identify long term transmission expansion plan.
-

PUBLIC DISCLOSURE

East Watkinsville - Russell Dam 230kV
P: 1889731 & 32
Estimate Basis Document for Comparative/Conceptual Estimating Only

ATTACHMENT D

PRELIMINARY
FOR COMPARATIVE ESTIMATE ONLY

GPC-1101
Date: 02/07/19

Scope

Replace the existing 1351 ACSR-SD conductor for all 4 miles from East Watkinsville Substation (GTC) to Russell Dam Substation (SEPA). There are 216 existing structures & 215 spans.
East Watkinsville Sub (GTC) - Lexington Sub (GTC) is 17.1 miles
Lexington Sub (GTC) - Russell Dam Sub (SEPA) is 31.3 miles

The existing line is predominantly 230kV Steel Guyed Lattice H-Frames with 16-bell insulator strings. There are (2) 3/8" HS Steel OHGWs on the existing line which are planned to remain. The original line construction was in 1983.

1351 ACSR			1351-T13 ACCR			1622-T13 ACCR/TW			1351 ACSS-HS (Replace all structures)			1351 ACSS-HS (Upgrade)			(2) 795 ACSR Bundle		
		Difference			Difference			Difference			Difference			Difference			Difference
Ampacity (Amps)	1436	BASE	Ampacity (Amps)	2229	+773	Ampacity (Amps)	2466	+1030	Ampacity (Amps)	2248	+732	Ampacity (Amps)	2248	+732	Ampacity (Amps)	2182	+436
[redacted]																	
Structure Replace	53 of 216	BASE	Structure Replace	21 of 216	-34 str	Structure Replace	53 of 216	-2 str	Structure Replace	216 of 216	+161 str	Structure Replace	80 of 216	+25 str	Structure Replace	164 of 216	+109 str
% Raised or Replaced	33%	—	% Raised or Replaced	21%	—	% Raised or Replaced	37%	—	% Raised or Replaced	100%	—	% Raised or Replaced	85%	—	% Raised or Replaced	93%	—
[redacted]																	

Explanation of Costs

Construction (Install & Removal)

Contractor Labor & Equip: The estimated $80k/week per crew ($320k/week for 4 crews)
Reconductor (remove existing, string new wire, clip-in, add dampers, etc.) 2 weeks / mile (4 crews)
Sectional Reconductor (1.2 x single wire per phase duration) 3 weeks / mile (4 crews)

Structure Labor & Equip: The estimated $52k/week per crew
Raise an existing tangent tower (+10' to 20') and install new guying 2 crew days / str = 2.5 wks / str
Replace an existing tangent tower with a new 125' SHF 4 crew days / str = 1 wk / str
Add Upgrade/Replace Guying on all remaining 3-Pole Towers 2 crew days / str = 2.5 wks / str
Replace an existing medium angle or DE tower with a new 125' 3-Pole 6 crew days / str = 2 wks / str

Crane Rental: Estimated for $20k/week for raising structures or structure replacements.

Special Equipment: 72" Bullwheel Tensioner for ACCR conductors (assume $40k/week x 2 for working from separate ends)

Material Estimate:
See material cost table below
Conductor Only: OHGW planned to remain. Conductor length includes 3% increase.

Engineering

R/W Support

Crew Support: Jeff estimated $40k/wk for heavy crew support and 4 crews. Duration is 4 wk before + constr. + 4 wks after. Per Jeff, 1st section has better access (pasture land), 2nd section has wooded areas and significant secondary access off R/W will be needed (crew support will likely be 25% more for this section).

Erosion Control: $2.5k/week per crew (4 crews)

Clearing/Trimming: Not considered for this estimate

Culvert Repair: Jeff estimated $140k for culvert repair

Barge Grass Stimulating: Per Larry Hester
Ground (16) H-Frame / week @ $611.75/ea
Ground (14) 3-Pole / week @ $56.11/ea

Location Yard Labor: Estimated for 1 mo before + full crew support duration + 1 mo after (3 yards x $8k yard/mo)

Mats: 1000 Mats x 2 (assume starting from separate ends) purchase for $2M

Rock Drilling/Excavation: Not considered for this estimate

Notes:
1. The estimates assume all clearance issues in distribution crossings or transmission crossings will be accomplished by lowering or modifying the crossing line. No cost is included in the estimate for this work.
2. The estimates are based on a minimum required ground clearance of NESC + 4' (28.5') which is less than SCS required ground clearance (30') for new construction.
3. The estimates do not include tower replacements for deterioration or maintenance. ABS/TS did not indicate any tower replacement requirements. Jay Peach confirmed the last inspection was a slow groundline inspection in 2017.
4. The estimates do not include replacement of insulator strings, except for structure replacements. The assessment is based on re-using the existing 16-bell insulator strings.
5. The estimates are based on ACCR conductor cost of $11.03/ft based on range of $9.00-$12.00/ft from Mark Smith.
6. Replacing an existing tower includes installation of the new structure and removal of the existing tower in the labor estimate.
7. 1622-T13 ACCR/TW clamps and hardware cost based on 1351 ACSR cost multiplied by 1.25. 1351-T13 ACCR assumed to use same clamps and hardware as 1351 ACSR.
8. 3M confirmed a minimum 72" bullwheel tensioner is required for 1351 or 1622 ACCR conductor. 3M also confirmed 36" Stringing Blocks are needed for tangent structures and rotary array blocks for angles & break-over locations.
9. Ampacity ratings are provided by SCS Planning for 95°F ambient air temperature. ACCR Temperature limit is 180°C & ACCR/ACSS Temperature limit is 200°C, based on SCS limits.
10. If the OHGWs are replaced in kind during the reconductor project, it would result in an additional cost of $3M (construction labor, R/W support, and material) and an additional construction duration of 12 weeks (based on 4 crews).

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:03:58 AM

Project Item:	1689707			
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV		Job ID:	1689707
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor			
Job Type:	MODIFICATION		Job Status:	WORKING
Area:	CENTRAL-ATHENS		Region:	NORTHEAST
In Service Date:	12/16/2020 (Scheduled)	Facility Required Date: 12/31/2020	Owner:	GPCO
Project Manager:	[redacted]			

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	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	HPB01	PR_SS	0
HPB01	BUDGET APPROVAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
PEGWO	CREATE WORK ORDER	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	2
CELDP	DESIGN PLANNING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELDP	PR_FS	0
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	5
ALL04	PROPERTY RESEARCH	[redacted]	S	[redacted]	S	SEPR	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	0
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	0
ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALL04	PR_FS	0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	2
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	2.5
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	2.5
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	X2CD	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	6.25
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	2
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_SS	2
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
DELPT01	INITIATE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JFWE	JMIS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	CEL01	PR_SS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	ENVR01	PR_FS	10
ALS09	CONSTRUCTION SUPPORT PLAN SHEETS	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	5
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	0
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
BLRLAY	LAYDOWN YARD	[redacted]	S	[redacted]	S	RAWE	GWSC	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	10
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	0
DELPT02	RECEIVE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	15
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE

Date:02/19/2020
Time:11:03:58 AM

Project Item:	1689707		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689707
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	12/16/2020 (Scheduled) Facility Required Date: 12/31/2020	Owner:	GPCO
Project Manager:	[redacted]		

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS06	PR_FS	4
		[redacted]		[redacted]				[redacted]	FCL01	PR_SS	-16
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS09	PR_FS	0
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	BLRLAY	PR_FS	10
		[redacted]		[redacted]				[redacted]	CULT01	PR_FS	0
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	30.4
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	EEGREV	PR_FS	12
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	DEL02	PR_FS	40
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-10
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	BIDFCL	PR_FS	10
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-20
ALS04B	FINAL STAKING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL02	PR_FS	10
		[redacted]		[redacted]				[redacted]	FCL01	PR_FS	10
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-15
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	0
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	-40
		[redacted]		[redacted]				[redacted]	SHIPPING	PR_FS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	GCL01	PR_FF	0
GCL02	INSTALL COUNTERPOISE	[redacted]	S	[redacted]	S	KEWH	KEWH	[redacted]	GCL01	PR_FF	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL03	PR_FS	0
HPB02	REQUIRED FINISH/ IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	ALS04B	PR_FS	0
									DEL03	PR_FS	0
									DESC	PR_FF	0
									FCL03	PR_FS	0
									FCLNOI	PR_FS	0
									GCL02	PR_FF	0
									MCL01	PR_FS	0

GEORGIA POWER COMPANY
Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:03:58 AM

Project Item:	1689707		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689707
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	12/16/2020 (Scheduled) Facility Required Date: 12/31/2020	Owner:	GPCO
Project Manager:	[redacted]		

									OUTAGE	PR_FS	0
									REPE3	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	ALS02F	PR_FS	0
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	ALS02F	PR_FS	0
									DELDOC	PR_FS	0

*** End of Report ***

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:03:59 AM

Project Item:	1689708		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689708
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	5/17/2021 (Scheduled) Facility Required Date: 6/1/2021	Owner:	GPCO
Project Manager:	[redacted]		

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	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	HPB01	PR_SS	0
HPB01	BUDGET APPROVAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
PEGWO	CREATE WORK ORDER	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	5
CELDP	DESIGN PLANNING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELDP	PR_FS	0
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
ALL04	PROPERTY RESEARCH	[redacted]	S	[redacted]	S	SEPR	LCAR	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALL04	PR_FS	0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	3
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	5
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	X2CD	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	6.25
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	5
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	5
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_SS	5
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JFWE	JMIS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	CEL01	PR_SS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	ENVR01	PR_FS	10
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
DELPT01	INITIATE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS09	CONSTRUCTION SUPPORT PLAN SHEETS	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	5
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	0
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
BLRLAY	LAYDOWN YARD	[redacted]	S	[redacted]	S	RAWE	GWSC	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	10
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	0
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
DELPT02	RECEIVE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	60

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:03:59 AM

Project Item: 1689708
Job Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV
Job ID: 1689708
Job Desc: Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor
Job Type: MODIFICATION
Job Status: WORKING
Area: CENTRAL-ATHENS
Region: NORTHEAST
In Service Date: 5/17/2021 (Scheduled)
Facility Required Date: 6/1/2021
Owner: GPCO
Project Manager: [redacted]

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS06	PR_FS	4
		[redacted]		[redacted]				[redacted]	FCL01	PR_SS	-16
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	-40
		[redacted]		[redacted]				[redacted]	SHIPPING	PR_FS	0
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	BIDFCL	PR_FS	10
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-20
ALS04B	FINAL STAKING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL02	PR_FS	10
		[redacted]		[redacted]				[redacted]	FCL01	PR_FS	10
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-15
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	DEL02	PR_FS	40
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-10
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS09	PR_FS	0
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	BLRLAY	PR_FS	10
		[redacted]		[redacted]				[redacted]	CULT01	PR_FS	0
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	32
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	EEGREV	PR_FS	12
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	GCL01	PR_FF	0
GCL02	INSTALL COUNTERPOISE	[redacted]	S	[redacted]	S	KEWH	KEWH	[redacted]	GCL01	PR_FF	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL03	PR_FS	0
HPB02	REQUIRED FINISH/ IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	ALS04B	PR_FS	0
									DEL03	PR_FS	0
									DESC	PR_FF	0
									FCL03	PR_FS	0
									FCLNOI	PR_FS	0
									GCL02	PR_FF	0
									MCL01	PR_FS	0

GEORGIA POWER COMPANY
Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:03:59 AM

Project Item: 1689708
Job Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV — Job ID: 1689708
Job Desc: Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor
Job Type: MODIFICATION — Job Status: WORKING
Area: CENTRAL-ATHENS — Region: NORTHEAST
In Service Date: 5/17/2021 (Scheduled) — Facility Required Date: 6/1/2021 — Owner: GPCO
Project Manager: [redacted]

									OUTAGE	PR_FS	0
									REPE3	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	ALS02F	PR_FS	0
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	ALS02F	PR_FS	0
									DELDOC	PR_FS	0

*** End of Report ***

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:01 AM

Project Item:	1689709		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689709
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	12/15/2021 (Scheduled) Facility Required Date: 12/31/2021	Owner:	GPCO
Project Manager:	[redacted]		

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	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			HPB01	PR_SS	0
HPB01	BUDGET APPROVAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			0		0
PEGWO	CREATE WORK ORDER	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]			HPB01	PR_FS	0
CELDP	DESIGN PLANNING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			PEGWO	PR_FS	0
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			CELDP	PR_FS	0
		[redacted]		[redacted]				[redacted]			PEGWO	PR_FS	10
ALL04	PROPERTY RESEARCH	[redacted]	S	[redacted]	S	SEPR	LCAR	[redacted]			REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			REPE2	PR_FS	10
ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			ALL04	PR_FS	0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			ALS01	PR_FS	3
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	DMRI	[redacted]			ALS02	PR_SS	5
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	X2CD	[redacted]			ALS02	PR_SS	6.25
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			ALS02	PR_FS	5
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			ALS03	PR_FS	10
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JFWE	JMIS	[redacted]			ALS03	PR_FS	10
		[redacted]		[redacted]				[redacted]			CEL01	PR_SS	10
		[redacted]		[redacted]				[redacted]			ENVR01	PR_FS	10
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CEL01	PR_FS	0
DELPT01	INITIATE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CEL01	PR_FS	0
ALS09	CONSTRUCTION SUPPORT PLAN SHEETS	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			CEL01	PR_FS	5
BLRLAY	LAYDOWN YARD	[redacted]	S	[redacted]	S	RAWE	GWSC	[redacted]			CEL01	PR_FS	10
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CEL01	PR_FS	15
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CELRVW	PR_FS	0
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			CELRQN	PR_FS	0
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			DEL01	PR_FS	0
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]			DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]			DEL02	PR_FS	10
DELPT02	RECEIVE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			DELPT01	PR_FS	60

GEORGIA POWER COMPANY
Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:01 AM

Project Item: 1689709
Job Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV
Job ID: 1689709
Job Desc: Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor
Job Type: MODIFICATION
Job Status: WORKING
Area: CENTRAL-ATHENS
Region: NORTHEAST
In Service Date: 12/15/2021 (Scheduled)
Facility Required Date: 12/31/2021
Owner: GPCO
Project Manager: [redacted]

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS06	PR_FS	4
									FCL01	PR_SS	-16
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	-40
									SHIPPING	PR_FS	0
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	BIDFCL	PR_FS	10
									DEL02	PR_FS	6.4
									DELPT02	PR_FS	6.4
									GCL01	PR_SS	-20
ALS04B	FINAL STAKING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL02	PR_FS	10
									FCL01	PR_FS	10
									GCL01	PR_SS	-15
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	DEL02	PR_FS	40
									GCL01	PR_SS	-10
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS09	PR_FS	0
									GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	BLRLAY	PR_FS	10
									CULT01	PR_FS	0
									DEL02	PR_FS	32
									DELPT02	PR_FS	6.4
									EEGREV	PR_FS	12
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	GCL01	PR_FF	0
GCL02	INSTALL COUNTERPOISE	[redacted]	S	[redacted]	S	KEWH	KEWH	[redacted]	GCL01	PR_FF	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL03	PR_FS	0
HPB02	REQUIRED FINISH/ IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	ALS04B	PR_FS	0
									DEL03	PR_FS	0
									DESC	PR_FF	0
									FCL03	PR_FS	0
									FCLNOI	PR_FS	0
									GCL02	PR_FF	0
									MCL01	PR_FS	0

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:01 AM

Project Item: 1689709
Job Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Job ID: 1689709
Job Desc: Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor
Job Type: MODIFICATION Job Status: WORKING
Area: CENTRAL-ATHENS Region: NORTHEAST
In Service Date: 12/15/2021 (Scheduled) Facility Required Date: 12/31/2021 Owner: GPCO
Project Manager: [redacted]

									OUTAGE	PR_FS	0
									REPE3	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	ALS02F	PR_FS	0
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	ALS02F	PR_FS	0
									DELDOC	PR_FS	0

*** End of Report ***

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE

Date:02/19/2020
Time:11:04:02 AM

Project Item:	1689710		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689710
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	6/1/2022 (Scheduled) Facility Required Date: 6/1/2022	Owner:	GPCO
Project Manager:	[redacted]		

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	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	HPB01	PR_SS	0
HPB01	BUDGET APPROVAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
PEGWO	CREATE WORK ORDER	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	1
CELDP	DESIGN PLANNING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELDP	PR_FS	0
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
ALL04	PROPERTY RESEARCH	[redacted]	S	[redacted]	S	SEPR	LCAR	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALL04	PR_FS	0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	2
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	5
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	X2CD	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	6.25
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	5
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	10
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JFWE	JMIS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	CEL01	PR_SS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	ENVR01	PR_FS	10
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
DELPT01	INITIATE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS09	CONSTRUCTION SUPPORT PLAN SHEETS	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	5
BLRLAY	LAYDOWN YARD	[redacted]	S	[redacted]	S	RAWE	GWSC	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	10
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	0
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	0
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
DELPT02	RECEIVE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	60

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:02 AM

Project Item:	1689710		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689710
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	6/1/2022 (Scheduled) Facility Required Date: 6/1/2022	Owner:	GPCO
Project Manager:	[redacted]		

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS06	PR_FS	4
		[redacted]		[redacted]				[redacted]	FCL01	PR_SS	-16
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	-40
		[redacted]		[redacted]				[redacted]	SHIPPING	PR_FS	0
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	BIDFCL	PR_FS	10
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-20
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	DEL02	PR_FS	40
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-18.75
ALS04B	FINAL STAKING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL02	PR_FS	10
		[redacted]		[redacted]				[redacted]	FCL01	PR_FS	10
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-15
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS09	PR_FS	0
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	BLRLAY	PR_FS	10
		[redacted]		[redacted]				[redacted]	CULT01	PR_FS	0
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	32
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	EEGREV	PR_FS	12
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	GCL01	PR_FF	0
GCL02	INSTALL COUNTERPOISE	[redacted]	S	[redacted]	S	KEWH	KEWH	[redacted]	GCL01	PR_FF	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL03	PR_FS	0
HPB02	REQUIRED FINISH/ IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	ALS04B	PR_FS	0
									DEL03	PR_FS	0
									DESC	PR_FF	0
									FCL03	PR_FS	0
									FCLNOI	PR_FS	0
									GCL02	PR_FF	0

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:02 AM

Project Item:	1689710		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689710
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	6/1/2022 (Scheduled) Facility Required Date: 6/1/2022	Owner:	GPCO
Project Manager:	[redacted]		

									MCL01	PR_FS	0
									OUTAGE	PR_FS	0
									REPE3	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	ALS02F	PR_FS	0
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	ALS02F	PR_FS	0
									DELDOC	PR_FS	0

*** End of Report ***

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE

Date:02/19/2020
Time:11:04:03 AM

Project Item:	1689711		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689711
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	12/16/2022 (Scheduled) Facility Required Date: 12/31/2022	Owner:	GPCO
Project Manager:	[redacted]		

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	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			HPB01	PR_SS	0
HPB01	BUDGET APPROVAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			0		0
PEGWO	CREATE WORK ORDER	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]			HPB01	PR_FS	1
CELDP	DESIGN PLANNING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			PEGWO	PR_FS	0
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			CELDP	PR_FS	0
		[redacted]		[redacted]				[redacted]			PEGWO	PR_FS	10
ALL04	PROPERTY RESEARCH	[redacted]	S	[redacted]	S	SEPR	LCAR	[redacted]			REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			REPE2	PR_FS	10
ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			ALL04	PR_FS	0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			ALS01	PR_FS	2
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	DMRI	[redacted]			ALS02	PR_SS	5
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	X2CD	[redacted]			ALS02	PR_SS	6.25
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			ALS02	PR_FS	5
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			ALS03	PR_FS	10
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JFWE	JMIS	[redacted]			ALS03	PR_FS	10
		[redacted]		[redacted]				[redacted]			CEL01	PR_SS	10
		[redacted]		[redacted]				[redacted]			ENVR01	PR_FS	10
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CEL01	PR_FS	0
DELPT01	INITIATE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CEL01	PR_FS	0
ALS09	CONSTRUCTION SUPPORT PLAN SHEETS	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]			CEL01	PR_FS	5
BLRLAY	LAYDOWN YARD	[redacted]	S	[redacted]	S	RAWE	GWSC	[redacted]			CEL01	PR_FS	10
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CELRVW	PR_FS	0
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			DEL01	PR_FS	0
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]			DEL02	PR_FS	10
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]			DEL02	PR_FS	10
DELPT02	RECEIVE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			DELPT01	PR_FS	60
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]			CEL01	PR_FS	200
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]			CELRQN	PR_FS	100

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:03 AM

Project Item:	1689711		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689711
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	12/16/2022 (Scheduled) Facility Required Date: 12/31/2022	Owner:	GPCO
Project Manager:	[redacted]		

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS06	PR_FS	4
									FCL01	PR_SS	-16
MCL01	RECEIVE MATERIAL		S		S	HLUN	ANAL		GCL01	PR_SS	-40
									SHIPPING	PR_FS	0
FCL01	CLEAR R/W		S		S	GEGI	GEGI		BIDFCL	PR_FS	10
									DEL02	PR_FS	6.4
									DELPT02	PR_FS	6.4
									GCL01	PR_SS	-20
ALS04B	FINAL STAKING		S		S	JFWE	BJCO		DEL02	PR_FS	10
									FCL01	PR_FS	10
									GCL01	PR_SS	-15
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE		S		S	HLUN	ANAL		DEL02	PR_FS	40
									GCL01	PR_SS	-10
FCL03	CREW SUPPORT		S		S	GEGI	GEGI		ALS09	PR_FS	0
									GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION		S		S	UNAS	UNAS		BLRLAY	PR_FS	10
									CULT01	PR_FS	0
									DEL02	PR_FS	32
									DELPT02	PR_FS	6.4
									EEGREV	PR_FS	12
OUTAGE	LINE OUTAGE - CAPITAL		S		S	HLUN	ANAL		GCL01	PR_SS	0
DEL03	FINAL INSPECTION		S		S	UNAS	UNAS		GCL01	PR_FF	0
GCL02	INSTALL COUNTERPOISE		S		S	KEWH	KEWH		GCL01	PR_FF	0
HPB02	REQUIRED FINISH/ IN-SERVICE DATE		S		S	HLUN	ANAL		ALS04B	PR_FS	0
									DEL03	PR_FS	0
									DESC	PR_FF	0
									FCL03	PR_FS	0
									FCLNOI	PR_FS	0
									GCL02	PR_FF	0
									MCL01	PR_FS	0
									OUTAGE	PR_FS	0

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:03 AM

Project Item:	1689711		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689711
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	12/16/2022 (Scheduled) Facility Required Date: 12/31/2022	Owner:	GPCO
Project Manager:	[redacted]		

									REPE3	PR_FS	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL03	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	ALS02F	PR_FS	0
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	ALS02F	PR_FS	0
									DELDOC	PR_FS	0

*** End of Report ***

GEORGIA POWER COMPANY

Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:04 AM

Project Item:	1689712			
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV		Job ID:	1689712
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor			
Job Type:	MODIFICATION		Job Status:	WORKING
Area:	CENTRAL-ATHENS		Region:	NORTHEAST
In Service Date:	6/1/2023 (Scheduled)	Facility Required Date: 6/1/2023	Owner:	GPCO
Project Manager:	[redacted]			

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	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	HPB01	PR_SS	0
HPB01	BUDGET APPROVAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
PEGWO	CREATE WORK ORDER	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	1
CELDP	DESIGN PLANNING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELDP	PR_FS	0
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
ALL04	PROPERTY RESEARCH	[redacted]	S	[redacted]	S	SEPR	LCAR	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALL04	PR_FS	0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	2
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	5
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	ASHE	X2CD	[redacted]	[redacted]	[redacted]	ALS02	PR_SS	6.25
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	5
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	10
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JFWE	JMIS	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	CEL01	PR_SS	10
		[redacted]		[redacted]				[redacted]	[redacted]	[redacted]	ENVR01	PR_FS	10
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
DELPT01	INITIATE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS09	CONSTRUCTION SUPPORT PLAN SHEETS	[redacted]	S	[redacted]	S	JFWE	JUMO	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	5
BLRLAY	LAYDOWN YARD	[redacted]	S	[redacted]	S	RAWE	GWSC	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	10
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	0
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
DELPT02	RECEIVE SPECIAL PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	60
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	300

GEORGIA POWER COMPANY
Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:04 AM

Project Item:	1689712		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689712
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	6/1/2023 (Scheduled) Facility Required Date: 6/1/2023	Owner:	GPCO
Project Manager:	[redacted]		

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS06	PR_FS	4
		[redacted]		[redacted]				[redacted]	FCL01	PR_SS	-16
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	-40
		[redacted]		[redacted]				[redacted]	SHIPPING	PR_FS	0
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	BIDFCL	PR_FS	10
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-20
ALS04B	FINAL STAKING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL02	PR_FS	10
		[redacted]		[redacted]				[redacted]	FCL01	PR_FS	10
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-15
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	DEL02	PR_FS	40
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	-10
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	ALS09	PR_FS	0
		[redacted]		[redacted]				[redacted]	GCL01	PR_SS	0
GCL01	LINE CONSTRUCTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	BLRLAY	PR_FS	10
		[redacted]		[redacted]				[redacted]	CULT01	PR_FS	0
		[redacted]		[redacted]				[redacted]	DEL02	PR_FS	32
		[redacted]		[redacted]				[redacted]	DELPT02	PR_FS	6.4
		[redacted]		[redacted]				[redacted]	EEGREV	PR_FS	12
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	GCL01	PR_FF	0
GCL02	INSTALL COUNTERPOISE	[redacted]	S	[redacted]	S	KEWH	KEWH	[redacted]	GCL01	PR_FF	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	DEL03	PR_FS	0
HPB02	REQUIRED FINISH/ IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	ALS04B	PR_FS	0
									DEL03	PR_FS	0
									DESC	PR_FF	0
									FCL03	PR_FS	0
									FCLNOI	PR_FS	0
									GCL02	PR_FF	0
									MCL01	PR_FS	0

GEORGIA POWER COMPANY
Job Network Report

PUBLIC DISCLOSURE Date:02/19/2020
Time:11:04:04 AM

Project Item:	1689712		
Job Name:	EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV	Job ID:	1689712
Job Desc:	Reconductor the entire line, 48.3 miles of 100°C 1351.5 ACSR/SD Martin conductor		
Job Type:	MODIFICATION	Job Status:	WORKING
Area:	CENTRAL-ATHENS	Region:	NORTHEAST
In Service Date:	6/1/2023 (Scheduled) Facility Required Date: 6/1/2023	Owner:	GPCO
Project Manager:	[redacted]		

									OUTAGE	PR_FS	0
									REPE3	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	ALS02F	PR_FS	0
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	BJCO	[redacted]	ALS02F	PR_FS	0
									DELDOC	PR_FS	0

*** End of Report ***

TMCRET40 GEORGIA POWER COMPANY **PUBLIC DISCLOSURE** Date: 02/19/2020

 ESTIMATED COST BY RETIREMENT UNITS Time: 11:04:08AM

Project Item: 1689707

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2020

Nearest Town: 48.37 Originator: [redacted]

Description:

Section 1: Russell Dam - Str. #185. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (6.1 miles). Replace both OHGWs with 3/8" HS steel.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
356.3029.0000	LT	1	[redacted]			
356.3029.4001	LT	1				
ANCHOR GUY	EA	190				
ARM-STEEL TUBULAR CROSSARM	EA	2				
FIXTURES & GUYS (UNDER 110)	LT	1				
GROUNDING-COUNTERPOISE	FT	1,778				
GROUNDING-STANDARD GROUND GAL	EA	99				
INSULATOR-SUSPENSION 230KV	SE	7				
INSUL-HORIZONTAL POST 230KV	SE	5				
POLES/TOWERS-ACCESSORIES	LT	1				
SET OF FIXTURES	LT	1				
STEEL POLE - 110'	EA	3				
STEEL POLE - 120'	EA	3				
STEEL POLE - 125'	EA	3				
STEEL POLE - 130'	EA	4				
STEEL POLE - 80'	EA	6				
STEEL POLE - 95'	EA	6				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
WIRE-ACCR,SGL COND 1351 KCMIL	FT	102,900				
WIRE-STEEL (OH GRND 3/8"	FT	68,600				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
FOUNDATIONS-RIGID BASE STRS	EA	10				
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS		-				
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	245				
GROUNDING-COUNTERPOISE	FT	7				
INSULATOR-SUSPENSION 230KV	SE	11				
STEEL POLE - 80'	EA	6				
STR-GUYED, ANGLE, TUB/LAT 75'	EA	1				
STR-GUYED, ANGLE, TUB/LAT 80'	EA	1				

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:08AM

Project Item: 1689707

PE: 6589 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV

Facility Required Date: 12/31/2020

Nearest Town: 48.37

Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
STR-GUYED, ANGLE, TUB/LAT100'	EA	2	[redacted]			
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
STR-GUYED, H-FRM, TUB/LAT100'	EA	3				
WIRE-ACSR,SGL COND 1351 KCMIL	FT	100,900				
WIRE-STEEL (OH GRND 3/8"	FT	67,300				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT REMOVALS						
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS						
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE						
TOTAL MAINTENANCE						

Project Item: 1689707

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2020

Nearest Town: 48.37 Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

ESTIMATED COST BY RETIREMENT UNITS

Project Item: 1689708

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2021

Nearest Town: 48.37 Originator: [redacted]

Description:

Section 2: Str. #185 - Str. #150. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (8.1 miles). Replace both OHGWs with 3/8" HS steel.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
356.3029.2134	LT	1	[redacted]			
356.3029.4001	LT	1				
ANCHOR GUY	EA	178				
ARM-STEEL TUBULAR CROSSARM	EA	7				
CONDUCTOR ACCESSORIES	LT	1				
FIXTURES & GUYS (UNDER 110)	LT	1				
GROUNDING-COUNTERPOISE	FT	2,032				
GROUNDING-STANDARD GROUND GAL	EA	17				
INSULATOR-SUSPENSION 230KV	SE	8				
INSUL-HORIZONTAL POST 230KV	SE	1				
POLES/TOWERS-ACCESSORIES	LT	1				
SET OF FIXTURES	LT	1				
STEEL POLE - 110'	EA	2				
STEEL POLE - 125'	EA	5				
STEEL POLE - 130'	EA	8				
STEEL POLE - 135'	EA	2				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
WIRE-ACCR,SGL COND 1351 KCMIL	FT	135,300				
WIRE-STEEL (OH GRND 3/8"	FT	90,200				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
FOUNDATIONS-RIGID BASE STRS	EA	9				
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS			-			
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	160				
GROUNDING-COUNTERPOISE	FT	8				
INSULATOR-SUSPENSION 230KV	SE	8				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
STR-GUYED, H-FRM, TUB/LAT 90'	EA	1				
STR-GUYED, H-FRM, TUB/LAT100'	EA	7				
WIRE-ACSR,SGL COND 1351 KCMIL	FT	132,700				

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:11AM

Project Item: 1689708

PE: 6589 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV

Facility Required Date: 6/1/2021

Nearest Town: 48.37

Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
WIRE-STEEL (OH GRND 3/8"	FT	88,500	[redacted]			
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT REMOVALS						
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS						
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE						
TOTAL MAINTENANCE						

Project Item: 1689708

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2021

Nearest Town: 48.37 Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

Project Item: 1689709

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2021

Nearest Town: 48.37 Originator: [redacted]

Description:

Section 3: Str. #150 - Str. #126. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (5.8 miles). Replace both OHGWs with 3/8" HS steel.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
356.3029.2134	LT	1	[redacted]			
356.3029.4001	LT	1				
ANCHOR GUY	EA	152				
ARM-STEEL TUBULAR CROSSARM	EA	2				
CONDUCTOR ACCESSORIES	LT	1				
FIXTURES & GUYS (UNDER 110)	LT	1				
GROUNDING-COUNTERPOISE	FT	762				
GROUNDING-STANDARD GROUND GAL	EA	7				
INSULATOR-SUSPENSION 230KV	SE	3				
INSUL-HORIZONTAL POST 230KV	SE	1				
POLES/TOWERS-ACCESSORIES	LT	1				
SET OF FIXTURES	LT	1				
STEEL POLE - 120'	EA	3				
STEEL POLE - 125'	EA	2				
STEEL POLE - 130'	EA	2				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
WIRE-ACCR,SGL COND 1351 KCMIL	FT	99,100				
WIRE-STEEL (OH GRND 3/8"	FT	66,100				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
FOUNDATIONS-RIGID BASE STRS	EA	4				
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS		-				
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	129				
GROUNDING-COUNTERPOISE	FT	3				
INSULATOR-SUSPENSION 230KV	SE	4				
STR-GUYED, ANGLE, TUB/LAT100'	EA	1				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
STR-GUYED, H-FRM, TUB/LAT100'	EA	2				
WIRE-ACSR,SGL COND 1351 KCMIL	FT	97,200				
WIRE-STEEL (OH GRND 3/8"	FT	64,800				

Project Item: 1689709

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2021

Nearest Town: 48.37 Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
WIRE-STEEL(OH GND	LT	1	[redacted]			
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT REMOVALS						
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS						
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE						
TOTAL MAINTENANCE						

Project Item: 1689709

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2021

Nearest Town: 48.37 Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:14AM

Project Item: 1689710

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2022

Nearest Town: 48.37 Originator: [redacted]

Description:

Section 4: Str. #126 - Lexington Substation. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (10.5 miles). Replace both OHGWs with 3/8" HS steel.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
356.3029.2134	LT	1	[redacted]			
356.3029.4001	LT	1				
ANCHOR GUY	EA	184				
ARM-STEEL TUBULAR CROSSARM	EA	1				
CONDUCTOR ACCESSORIES	LT	1				
FIXTURES & GUYS (UNDER 110)	LT	1				
GROUNDING-COUNTERPOISE	FT	762				
GROUNDING-STANDARD GROUND GAL	EA	8				
INSULATOR-SUSPENSION 230KV	SE	3				
INSUL-HORIZONTAL POST 230KV	SE	2				
POLES/TOWERS-ACCESSORIES	LT	1				
SET OF FIXTURES	LT	1				
STEEL POLE - 100'	EA	3				
STEEL POLE - 125'	EA	5				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
WIRE-ACCR,SGL COND 1351 KCMIL	FT	171,400				
WIRE-STEEL (OH GRND 3/8"	FT	114,300				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
FOUNDATIONS-RIGID BASE STRS	EA	4				
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS		-				
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	145				
GROUNDING-COUNTERPOISE	FT	3				
INSULATOR-SUSPENSION 230KV	SE	4				
STR-GUYED, ANGLE, TUB/LAT 80'	EA	1				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
STR-GUYED, H-FRM, TUB/LAT100'	EA	2				
WIRE-ACSR,SGL COND 1351 KCMIL	FT	168,100				
WIRE-STEEL (OH GRND 3/8"	FT	112,000				
WIRE-STEEL(OH GND	LT	1				

ESTIMATED COST BY RETIREMENT UNITS

Project Item: 1689710

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2022

Nearest Town: 48.37 Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
Discipline Total			**0**	[redacted]		
RIGHT OF WAY(Estimator: [redacted]				[redacted]		
RIGHT OF WAY CLEARING	LT	1	0	[redacted]		
ROW:CREW SUPPORT	LT	1	0	[redacted]		
Discipline Total			**0**	[redacted]		
Sub-Total PLANT REMOVALS			**0**	[redacted]		
PLANT TRANSFER REMOVALS				[redacted]		
Sub-Total PLANT TRANSFER REMOVALS			**0**	[redacted]		
TOTAL PLANT REMOVALS WITHOUT OVERHEADS				[redacted]		
MAINTENANCE				[redacted]		
Sub-Total MAINTENANCE			**0**	[redacted]		
TOTAL MAINTENANCE			**0**	[redacted]		

Project Item: 1689710

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2022

Nearest Town: 48.37 Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:17AM

Project Item: 1689711

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2022

Nearest Town: 48.37 Originator: [redacted]

Description:

Section 5: Lexington Substation - Str. #52. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (6.3 miles). Replace both OHGWs with 3/8" HS steel.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
356.3029.2134	LT	1	[redacted]			
356.3029.4001	LT	1				
ANCHOR GUY	EA	176				
ARM-STEEL TUBULAR CROSSARM	EA	1				
CONDUCTOR ACCESSORIES	LT	1				
FIXTURES & GUYS (UNDER 110)	LT	1				
GROUNDING-COUNTERPOISE	FT	1,016				
GROUNDING-STANDARD GROUND GAL	EA	11				
INSULATOR-SUSPENSION 230KV	SE	4				
INSUL-HORIZONTAL POST 230KV	SE	3				
POLES/TOWERS-ACCESSORIES	LT	1				
SET OF FIXTURES	LT	1				
STEEL POLE - 100'	EA	6				
STEEL POLE - 125'	EA	3				
STEEL POLE - 130'	EA	2				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
WIRE-ACCR,SGL COND 1351 KCMIL	FT	102,200				
WIRE-STEEL (OH GRND 3/8"	FT	68,100				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
FOUNDATIONS-RIGID BASE STRS	EA	6				
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS						
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	125				
GROUNDING-COUNTERPOISE	FT	4				
INSULATOR-SUSPENSION 230KV	SE	5				
STR-GUYED, ANGLE, TUB/LAT 85'	EA	1				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
STR-GUYED, H-FRM, TUB/LAT 70'	EA	1				
STR-GUYED, H-FRM, TUB/LAT100'	EA	2				
WIRE-ACSR,SGL COND 1351 KCMIL	FT	100,200				

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:17AM

Project Item: 1689711

PE: 6589 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV

Facility Required Date: 12/31/2022

Nearest Town: 48.37

Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
WIRE-STEEL (OH GRND 3/8"	FT	66,800	0	[redacted]		
WIRE-STEEL(OH GND	LT	1	0			
Discipline Total			**0**			
RIGHT OF WAY(Estimator: [redacted])						
RIGHT OF WAY CLEARING	LT	1	0			
ROW:CREW SUPPORT	LT	1	0			
Discipline Total			**0**			
Sub-Total PLANT REMOVALS			**0**			
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS			**0**			
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE			**0**			
TOTAL MAINTENANCE			**0**			

Project Item: 1689711

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 12/31/2022

Nearest Town: 48.37 Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:20AM

Project Item: 1689712

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2023

Nearest Town: 48.37 Originator: [redacted]

Description:

Section 6: Str. #52 - East Watkinsville. Reconductor this section, currently 100°C 1351.5 ACSR/SD Martin conductor, with 200°C 1351.5 ACCR Martin conductor (10.7 miles). Replace both OHGWs with 3/8" HS steel.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
356.3029.2134	LT	1	[redacted]			
356.3029.4001	LT	1				
ANCHOR GUY	EA	206				
ARM-STEEL TUBULAR CROSSARM	EA	2				
CONDUCTOR ACCESSORIES	LT	1				
FIXTURES & GUYS (UNDER 110)	LT	1				
GROUNDING-COUNTERPOISE	FT	1,270				
GROUNDING-STANDARD GROUND GAL	EA	13				
INSULATOR-SUSPENSION 230KV	SE	5				
INSUL-HORIZONTAL POST 230KV	SE	3				
POLES/TOWERS-ACCESSORIES	LT	1				
SET OF FIXTURES	LT	1				
STEEL POLE - 105'	EA	3				
STEEL POLE - 120'	EA	4				
STEEL POLE - 125'	EA	3				
STEEL POLE - 95'	EA	3				
STR-GUYED, H-FRAME, TUB/LAT	LT	1				
WIRE-ACCR,SGL COND 1351 KCMIL	FT	177,100				
WIRE-STEEL (OH GRND 3/8"	FT	118,000				
WIRE-STEEL(OH GND	LT	1				
Discipline Total						
ENGINEERING(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
RIGHT OF WAY(Estimator: [redacted])						
FOUNDATIONS-RIGID BASE STRS	EA	7				
RIGHT OF WAY CLEARING	LT	1				
ROW:CREW SUPPORT	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS		-				
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	197				
GROUNDING-COUNTERPOISE	FT	4				
INSULATOR-SUSPENSION 230KV	SE	5				
STR-GUYED, ANGLE, TUB/LAT 90'	EA	1				

Project Item: 1689712

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2023

Nearest Town: 48.37 Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
STR-GUYED, H-FRAME, TUB/LAT	LT	1	0	[redacted]		
STR-GUYED, H-FRM, TUB/LAT 85'	EA	1	0			
STR-GUYED, H-FRM, TUB/LAT100'	EA	2	0			
WIRE-ACSR,SGL COND 1351 KCMIL	FT	173,600	0			
WIRE-STEEL (OH GRND 3/8"	FT	115,700	0			
WIRE-STEEL(OH GND	LT	1	0			
Discipline Total			**0**			
RIGHT OF WAY(Estimator: [redacted])						
RIGHT OF WAY CLEARING	LT	1	0			
ROW:CREW SUPPORT	LT	1	0			
Discipline Total			**0**			
Sub-Total PLANT REMOVALS			**0**			
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS			**0**			
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE			**0**			
TOTAL MAINTENANCE			**0**			

ESTIMATED COST BY RETIREMENT UNITS

Project Item: 1689712

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: EAST WATKINSVILLE - RUSSELL DAM (USA) 230 KV Facility Required Date: 6/1/2023

Nearest Town: 48.37 Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

ESTIMATED COST BY RETIREMENT UNITS

Project Item: 1689713

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: LEXINGTON Facility Required Date: 6/1/2022

Nearest Town: LEXINGTON Originator: [redacted]

Description:

GTC - replace 1600A switches 101531 and 101543 with 3000A switches.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
Sub-Total PLANT ADDITIONS				[redacted]		
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS						
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
Sub-Total PLANT REMOVALS						
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS						
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE						
TOTAL MAINTENANCE						

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:21AM

Project Item: 1689713
PE: 6589 PE Item:
Version: Budget Saved
Type Work: MODIFICATION
Work Order:
Facility Name: LEXINGTON
Facility Required Date: 6/1/2022
Nearest Town: LEXINGTON
Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 ***

ESTIMATED COST BY RETIREMENT UNITS

Time: 11:04:24AM

Project Item: 1689714

PE: 6589 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: RUSSELL DAM (USA)

Facility Required Date: 6/1/2022

Nearest Town: ELBERTON

Originator: [redacted]

Description:

US Army Corps of Engineers - Replace 1590 AAC jumpers from the East Watkinsville 230 kV line (COE calls it Line #1) to the buswork between PCB's 138 and 148.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
Sub-Total PLANT ADDITIONS			[redacted]			
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS						
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
Sub-Total PLANT REMOVALS						
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS						
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE						
TOTAL MAINTENANCE						

Project Item: 1689714

PE: 6589 PE Item: Version: Budget Saved

Type Work: MODIFICATION Work Order:

Facility Name: RUSSELL DAM (USA) Facility Required Date: 6/1/2022

Nearest Town: ELBERTON Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
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 2021-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.

In the report headers, “DHOST” refers to the standard base case types that typically require projects or operating guides to be developed. “EPQR” cases have regional (MISO) flows added. Projects or operating guides do not necessarily have to be developed for constraints that occur in only MISO north-to-south or south-to-north flow cases. These case types are described more fully in Section D1, the 2021 Ten Year Expansion Plan.

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

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SOLUTIONS

2022-2031 TP-East Thermal Problems – v1B (DHOST)
Pages 1-24 are redacted in their entirety.

2022-2031 TP-East Thermal Problems – v1B (ERPQ)
Pages 1-31 are redacted in their entirety.

2022-2031 TP-East Thermal Problems – v2B (DHOST)
Pages 1-21 are redacted in their entirety.

2022-2031 TP-East Thermal Problems – v2B (ERPQ)
Pages 1-26 are redacted in their entirety.

2022-2031 TP-East Thermal Problems – v2B Winter
Pages 1-6 are redacted in their entirety.

[H1b]

VOLTAGE PROBLEMS

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SOLUTIONS

2022-2031 TP-East Voltage Problems – v1B DHOST
Pages 1-13 are redacted in their entirety.

2022-2031 TP-East Voltage Problems – v1B ERPQ
Pages 1-11 are redacted in their entirety.

2022-2031 TP-East Voltage Problems – v2B DHOST
Pages 1-10 are redacted in their entirety.

2022-2031 TP-East Voltage Problems – v2B ERPQ
Pages 1-7 are redacted in their entirety.

2022-2031 TP-East Voltage Problems – v2B Winter
Pages 1-12 are redacted in their entirety.

[H2]

LOAD FLOW DATA FILES

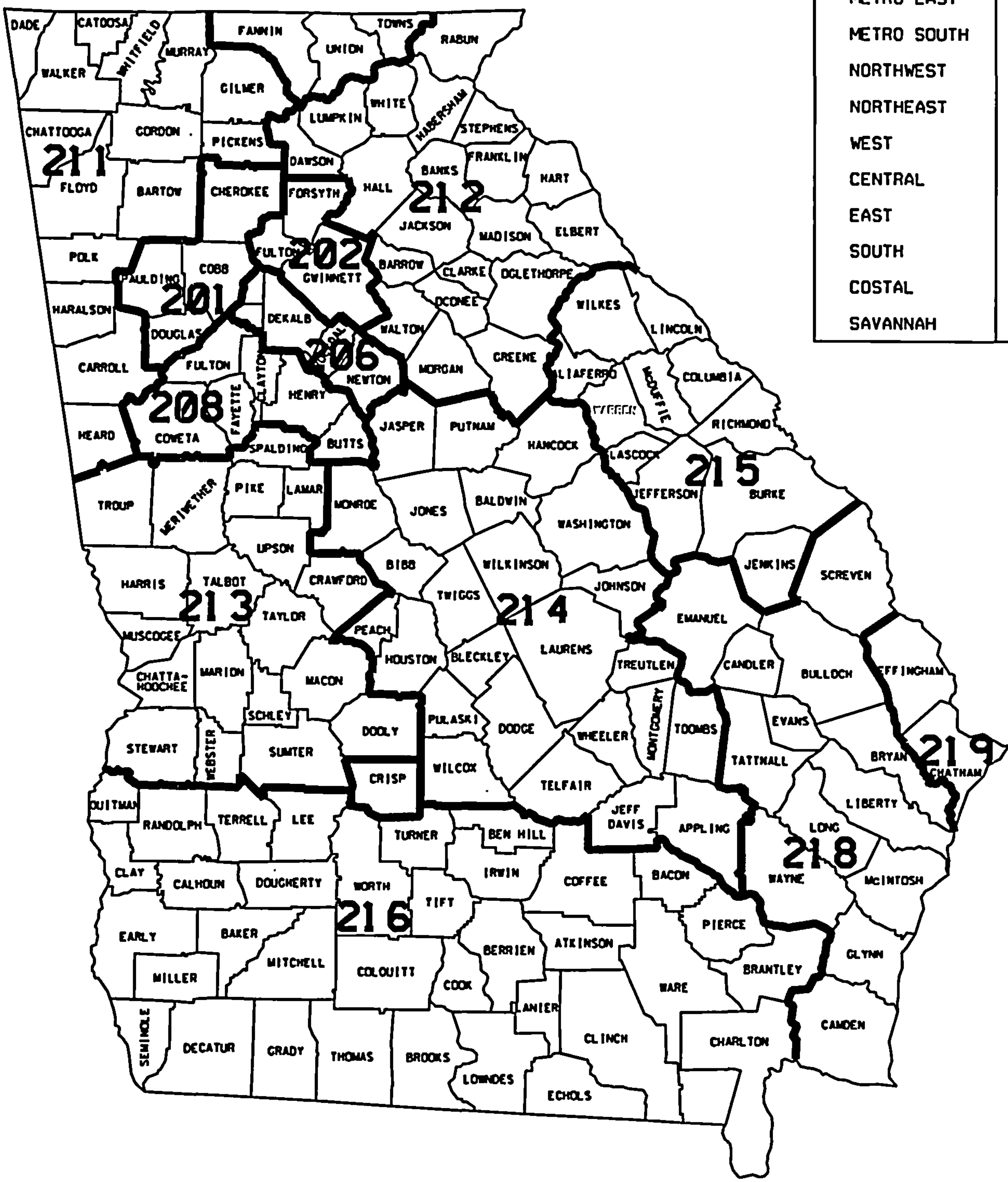
LOAD FLOW FILES REDACTED

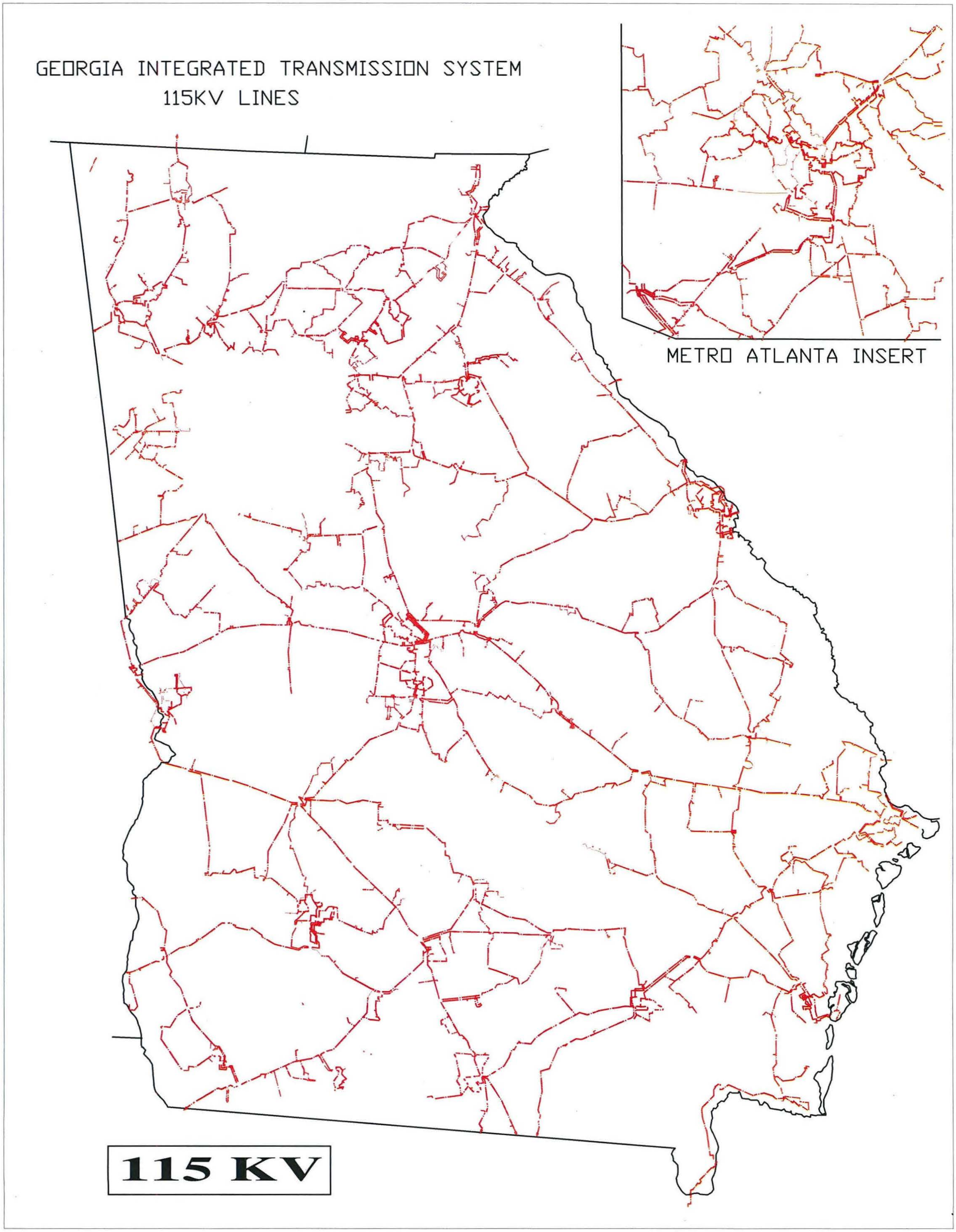
[H3]

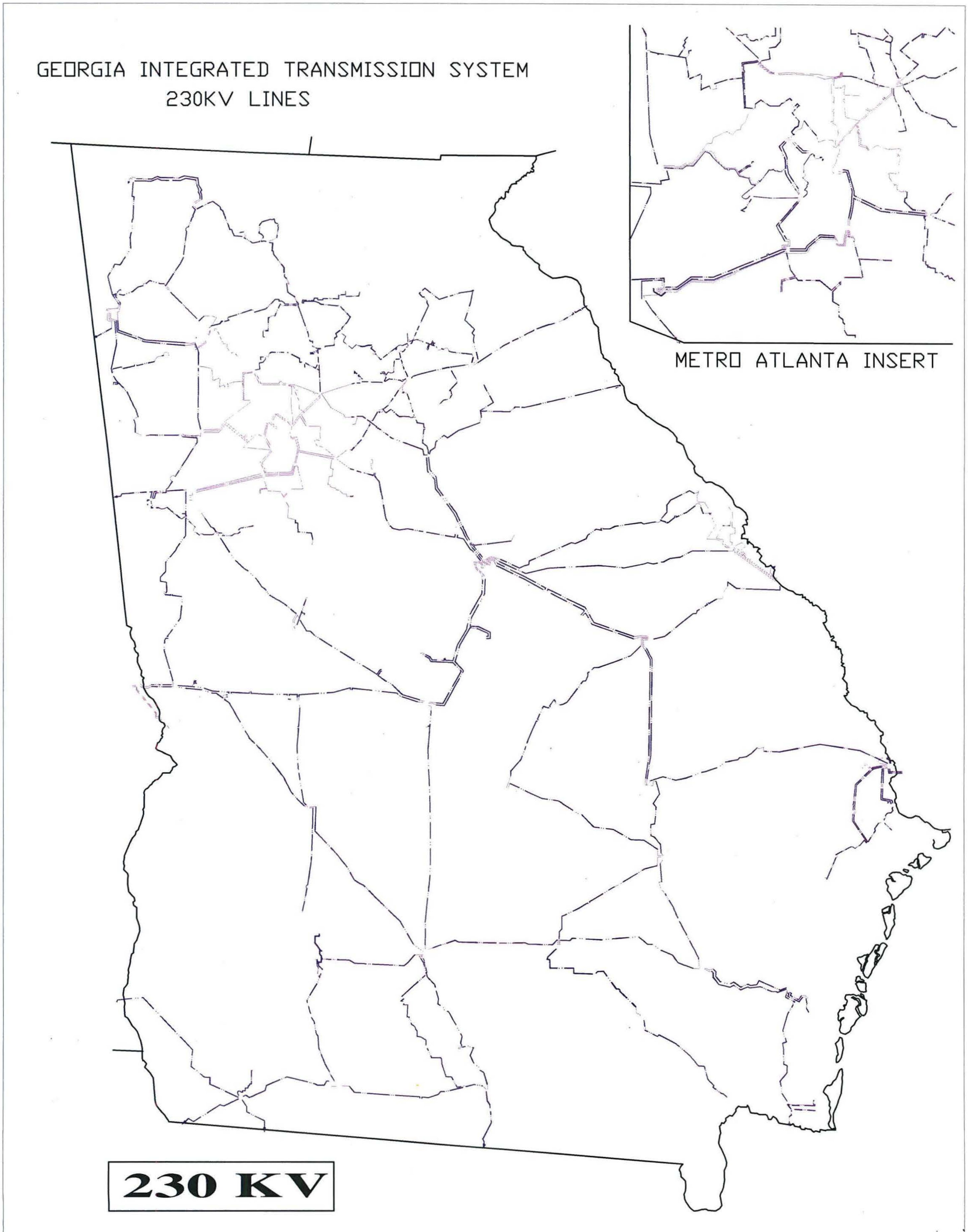
ITS MAPS

GEORGIA POWER REGION BOUNDARIES

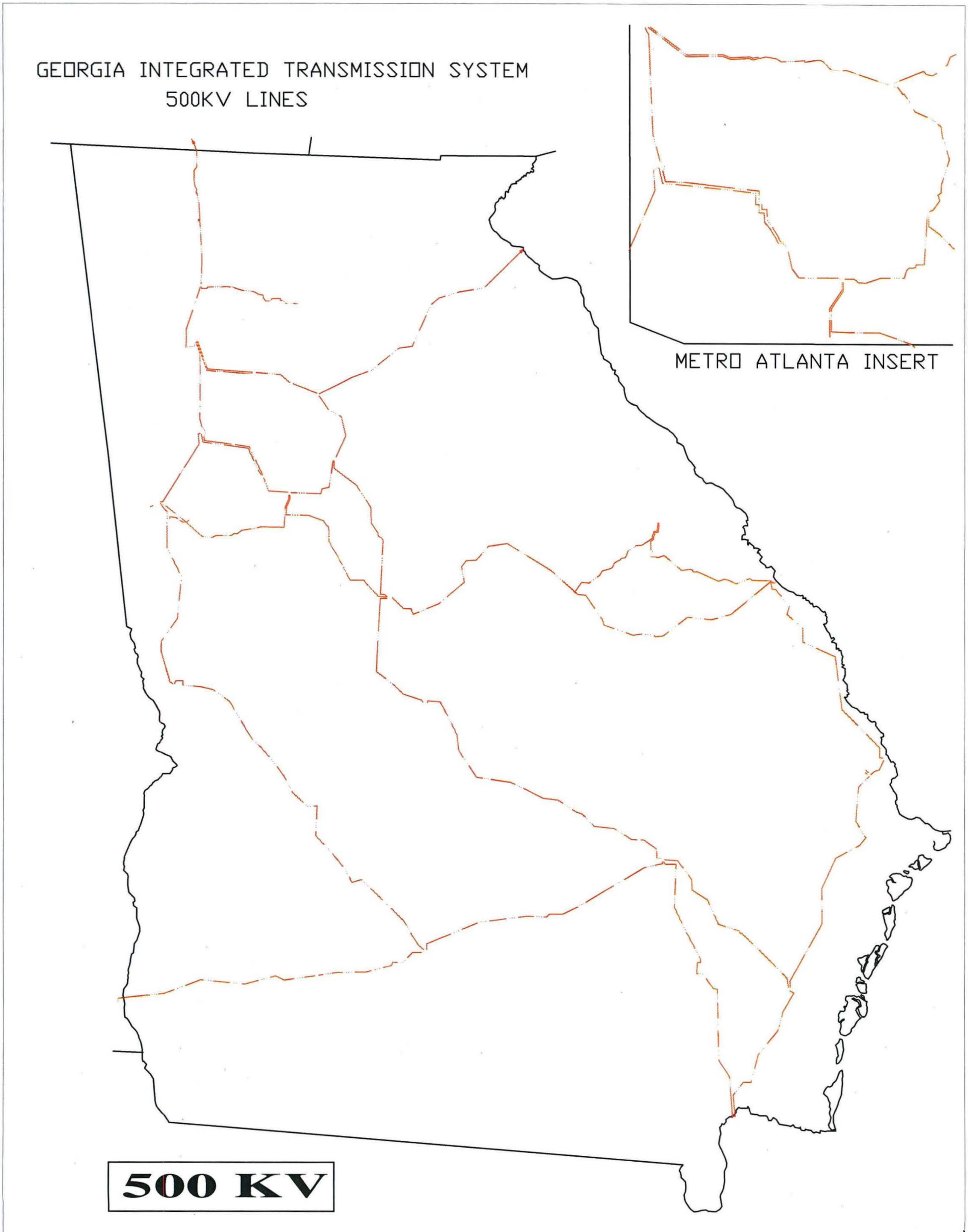
REGION	ZONE *
METRO WEST	201
METRO NORTH	202
METRO EAST	206
METRO SOUTH	208
NORTHWEST	211
NORTHEAST	212
WEST	213
CENTRAL	214
EAST	215
SOUTH	216
COSTAL	218
SAVANNAH	219




GEORGIA INTEGRATED TRANSMISSION SYSTEM
115KV LINES
METRO ATLANTA INSERT
115 KV


GEORGIA INTEGRATED TRANSMISSION SYSTEM
230KV LINES
METRO ATLANTA INSERT
230 KV

PUBLIC DISCLOSURE



[H4]

ACRONYMS, ABBREVIATIONS & TECHNICAL DEFINITIONS

Acronyms and Abbreviations:

ATC – Available Transfer Capability

BCA – Budget Change Authorization, documentation that provides information about the scope, budget, and schedule for capital projects at Georgia Power

BES – Bulk Electric System

CAP – Corrective Action Plan, filed annually with NERC

CBM – Capacity Benefit Margin

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

DER – Distributed Energy Resource

DESC – Dominion Energy South Carolina (previously SCE&G)

DSP – Distribution Service Provider

EIPC – Eastern Interconnection Planning Collaborative

ERAG – Eastern Interconnection Reliability Assessment Group

ERO – Electric Reliability Organization

FCITC – First Contingency Incremental Transfer Capability

FERC – Federal Energy Regulatory Commission

FRCC – Florida Reliability Coordinating Council

GPC – Georgia Power Company, Georgia ITS Participant

GO – Generation Owner

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

NITS – Network Integration Transmission Service

NLR – Native Load Reservation

OASIS – Open Access Same-Time Information System

OPC – Oglethorpe Power Corporation

PE – Plant Expenditure

PowerSouth – PowerSouth Energy Cooperative

PRICEM – GPC's Profitability / Reliability Incremental Cost Evaluation Model

PSEC – PowerSouth Energy Cooperative balancing authority

RC – Reliability Coordinator

SAV – Savannah area transmission network

SBA or SBAA – Southern Balancing Authority Area which 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

SCES – Southern Company Electric System

SEPA – Southeastern Power Administration

SERC – SERC Reliability Corporation

SME – Subject Matter Expert

SOS – Summer Operating Study, performed each Spring

STWG – ITS Sub-Transmission Working Group

SVS – Static VAR System

TEAMS – Transmission Evaluation and Management System

TIN – Transmission Improvement Notification

TO – Transmission Owner

TP-E – Transmission Planning - East

TPRT – Transmission Project Review Team

TPWG – ITS Transmission Planning Working Group, comprised of Transmission Planning representatives from each ITS Participant, meets monthly

TRM – Transmission Reliability Margin

TSA – Transmission Service Agreement

TSR – Transmission Service Request

TVA – Tennessee Valley Authority

TYP – ITS Ten Year Expansion Plan, published annually

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:

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).

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.

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.

Generation Loop Flows – loop flows occurring from the configuration of the network and location of generating units

ITC (Incremental Transfer Capability) – amount of transfer capability that can be accommodated in addition to the modeled base transfers.

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

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.

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.

Transaction Loop Flows – loop flows resulting from electric power transactions and the configuration of the network.

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.

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.

TTC (Total Transfer Capability) – base transfers plus incremental transfer capability