2025 IRP

TECHNICAL APPENDIX

VOLUME 3

TRANSMISSION PLAN

TECHNICAL APPENDIX
VOLUME 3
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FOREWORD

The documents presented in this volume of the IRP Technical Appendix represent a snapshot of Georgia Power's transmission and distribution (T&D) plan, as of December 2024. 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.

[A]

TRANSMISSION PLANNING DESCRIPTION & PROCESS

PUBLIC DISCLOSURE

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, 2023, Georgia Power's transmission system consisted of 46kV (2,150 miles), 69kV (76 miles), 115kV (5,826 miles), 230kV (2,528 miles), and 500kV (1,221 miles) lines totaling approximately 11,801 miles. This transmission system, along with other ITS transmission facilities, connected approximately 14,770 MW of GPC-owned, installed generating capacity in 2024. The total GPC residential, commercial, and industrial peak demand served in 2024 was approximately 16,596 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 Grid Transformation 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.
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 Planning and Policy 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.

PUBLIC DISCLOSURE

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.

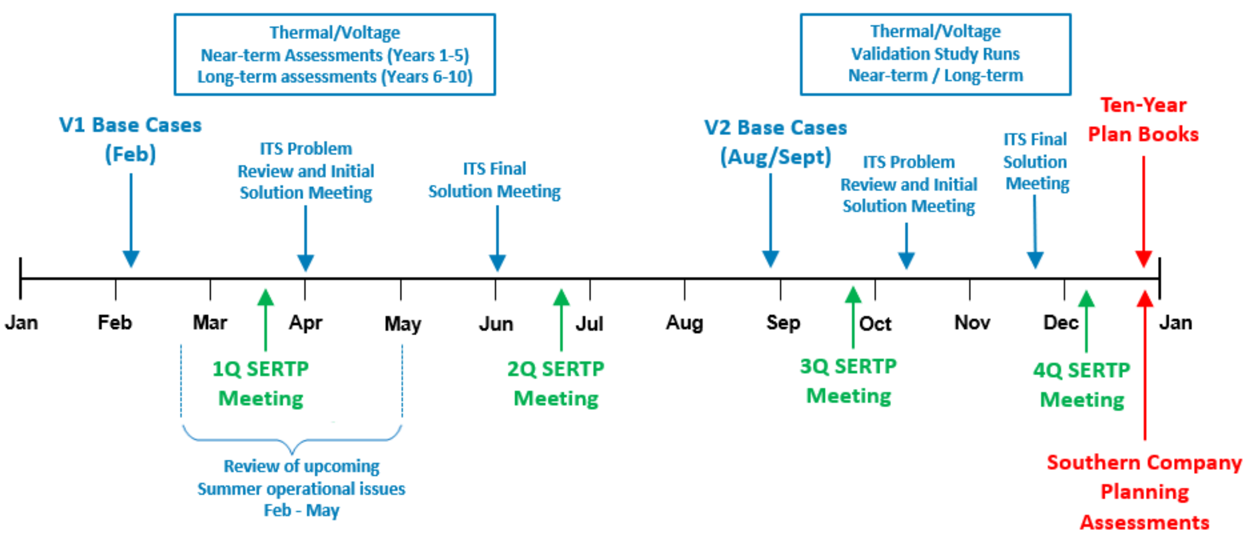
<u>LOAD FLOW</u>

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 as well as the magnitude and phase angle of all system voltages can be calculated. Given reliable input data, the load flow is an efficient model for steady-state conditions. Because of its accuracy and varied applications, the load flow model can be considered fundamental in steady-state analysis and 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; and
4. The evaluation of system performance

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 2024 Base Case is a load flow model for the summer coincident peak hour of 2024. It includes all transmission projects that have been or will be completed by May 1, 2024. 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,
- Alternative Transmission Technologies including some Grid-Enhancing Technologies (GETs), 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. A system is said to be stable 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.

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. Regional/area transmission.

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

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

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 under peak, shoulder, and off-peak load conditions. Further 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.

Overloads on the 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. The transmission planners use the load flow and transient stability program to test generator connections for 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 single phase to ground and two phases to ground.

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 500kV, 230kV, and 115kV circuit breakers at generating plants, switching stations, and 500/230kV or 230/115kV substations are rated higher than the maximum available fault current that might be encountered at these locations. In conjunction with the SCS Protection & Control Applications 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 performed to spot and solve any problems that might develop.

5. PLANNING COORDINATION WITH THE ITS

Planning for the ITS is a coordinated effort among the four ITS Participants. Interaction between GPC/SCS and the other 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 removed, or "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 create stripped cases independently and compare their cases to resolve any differences.

2. Throughout the year, screening results are reviewed.

   a. After 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, ITS planners responsible for the areas where 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 have the largest effects on 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 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 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 or commercial 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 Planning and 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 worsen?
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 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. Transmission Planning Engineers evaluate these options based on the aforementioned criteria and using planning-grade estimates for the cost comparisons.

Examples of 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 alternative transmission 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.
- 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 close to their ratings.
- Addition of reactive resources or current-limiting devices – By adding a capacitor bank, series reactor, or a shunt reactor, the system has more assets to help

operators better regulate real and reactive power flow. A reactive resource such as a capacitor bank might be selected if an area suffers from low voltage or a high reactive power requirement, while a current-limiting resource such as a series reactor might be selected if the area suffers from high power flow along a specific path to shift some of the power flow to nearby facilities with more available capacity. 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.

- Alternative Transmission Technologies (formally known as Non-Traditional Technologies) – GPC evaluates and installs cost-effective alternative transmission technologies including some GETs as needed to address specific system needs. Examples:
    - Static Synchronous Compensators (STATCOM) is a power electronics interfaced device whose primary function is to regulate voltage and improve stability by injecting or absorbing reactive power during a transient event.
    - Static VAR Compensators (SVC) is a power electronics interfaced device with a large portion of it being large passive components (such as shunt reactor banks, harmonic filter banks, etc.) whose primary function is to provide dynamic reactive power compensation, voltage regulation, and electrical stability to the surrounding network instead of pursuing transmission upgrade projects.
    - Advanced power flow controllers' primary function is to manage and optimize the flow of electrical power by adjusting parameters such as voltage, current, and phase angle, on the transmission line where the device is installed allowing to shift power flow off overloaded lines or increase power flow on underutilized lines.
    - Transmission Switching is the reconfiguration of the network by opening or closing switching devices to re-route power flow and decrease congestion in the transmission system.
    - Synchronous Condensers is a dynamic reactive power resource that provides or absorbs reactive power by helping maintain the voltage levels

within the desired range to improve power factor, allowing them to enhance the overall stability of the power system

- Voltage Source Converters (VSC) power electronic devices utilized to allow efficient power flow management and the integration of renewable energy sources. These devices are also used in HVDC systems to convert AC to DC and vice versa, providing flexible control on the amount of the power flow and even to reverse the power flow direction.
- Advanced conductors operate at higher temperatures, typically higher than 150°C, enabling high current-carrying capacity and reduce line losses to improve the efficiency, capacity, and reliability of electrical networks due to their composite and/or carbon cores. These conductors provide the option to reconductor, if existing structures can accommodate, to unlock additional capacity and avoid a full line rebuild.
- Tower Lifting is an advance technology solution to raise the height of existing transmission line towers to increase line clearance and capacity since it allows the lines to be operated at higher temperature rating.

6c. FEASIBILITY ANALYSIS

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

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

ELECTRICAL FEASIBILITY

In this activity, 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 solution feasibility process sheds additional light on the problems. This may result in problems being redefined, the suggestion of additional possible solutions, or the modification of a previous solution.

As in the definition of the problem, feasibility testing is performed using load flows. As previously stated, the base cases contain many assumptions. Transmission planners note and reflect these base case assumptions 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. GPC Land Department and Location Committee (concerning availability of R/W, guying and trimming rights, and substations sites),
2. Engineering (concerning design, protection, control, and construction matters),
3. System Operations (concerning protection, control, maintenance, and operating matters), and
4. Region and Transmission & Maintenance Center personnel (since they may have knowledge of all the above items).

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

6d. PROJECT EVALUATION

INTRODUCTION

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

The project selection criteria are centered on economic factors and engineering benefits. Both the economic and engineering analyses include the solution alternatives and other projects affected by 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 the above parameters are subject to change. Likewise, the performance criteria by which the model is tested can change. 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 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. <u>Environmental factors</u>

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

ECONOMIC EVALUATION

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

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

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

6e. RECOMMENDATION - PROJECT DOCUMENTATION

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

1. Management Summary

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

2. Assumption

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

3. Problem Statement

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

4. Discussion of Alternative Plans

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

5. Recommendation

   Statement of recommendation on the preferred plan.

6. Appendix

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

PUBLIC DISCLOSURE

This document is prepared for each special project 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 Grid Transformation (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 Transmission and Distribution (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 Items (PIs) 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 PIs are revised, explanations of these revisions are included in the details on the PI forms. Revisions are justified as to necessity, timing, and cost. If a change in estimated costs occurs in a PI 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. If the revision is greater than $1,000,000 for New Business projects or greater than $5,000,000 for all other projects, the proposal must flow through the T&D Council for final approval.

7c. BUDGETARY REVIEW AND CONTROL

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

In addition to the above periodic review of the Budget, drastic changes in the load forecast or in the GPC financial situation necessitates an immediate review of the Budget. Significant changes in the load forecast or generation expansion plan requires that each transmission project be reevaluated with respect to timing and scope. Sudden economic constraints placed on GPC expenditures require that each transmission project be reevaluated under revised capital availability.

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

8. TRANSMISSION PLANNING TOOLS

PSS/E Power System Simulator Program

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

PSS/E Load Flow Program

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

EMTP of PSCAD (Power Systems Computer Aided Design) - Electromagnetic Transients Program

These are a time-domain simulation programs that are 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, the simulation programs can also be used to study steady-state, unbalanced operation of power systems, and an inverter-based resource performance. They both have machine modeling capability which allows the study of the interaction of machines with power systems on a small scale. This capability is useful for studying phenomena such as sub-synchronous resonance.

Economic Dispatch Program

The Economic Dispatch Program was developed by SCS to interact with the Power Technologies Inc. load flow program, PSS/E. The program calculates an economic dispatch for a given load and spinning reserve requirement specified by the transmission planners and is based on the theory that the most economical dispatch is obtained by operating all on-line units at the same incremental cost (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.

REVREQ - Revenue Requirements Program

REVREQ is a program developed by SCS to generate capital recovery requirements associated with individual or multiple capitalized investments made within the SCES. REVREQ incorporates the effects of income tax credits, accelerated depreciation methods, income taxes, deferred taxes, ad valorem taxes, and capital costs into the calculations of revenue requirement schedules associated with the capital investment to be analyzed. The program uses specific Company related information or an average for the SCES in the determination of revenue requirements.

OHLOAD – Overhead Line Loading Program

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

<u>MUST - Managing and Utilizing System Transmission</u>

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.

<u>PSS SINCAL - Power System Simulator Siemens Network Calculation Tool</u>

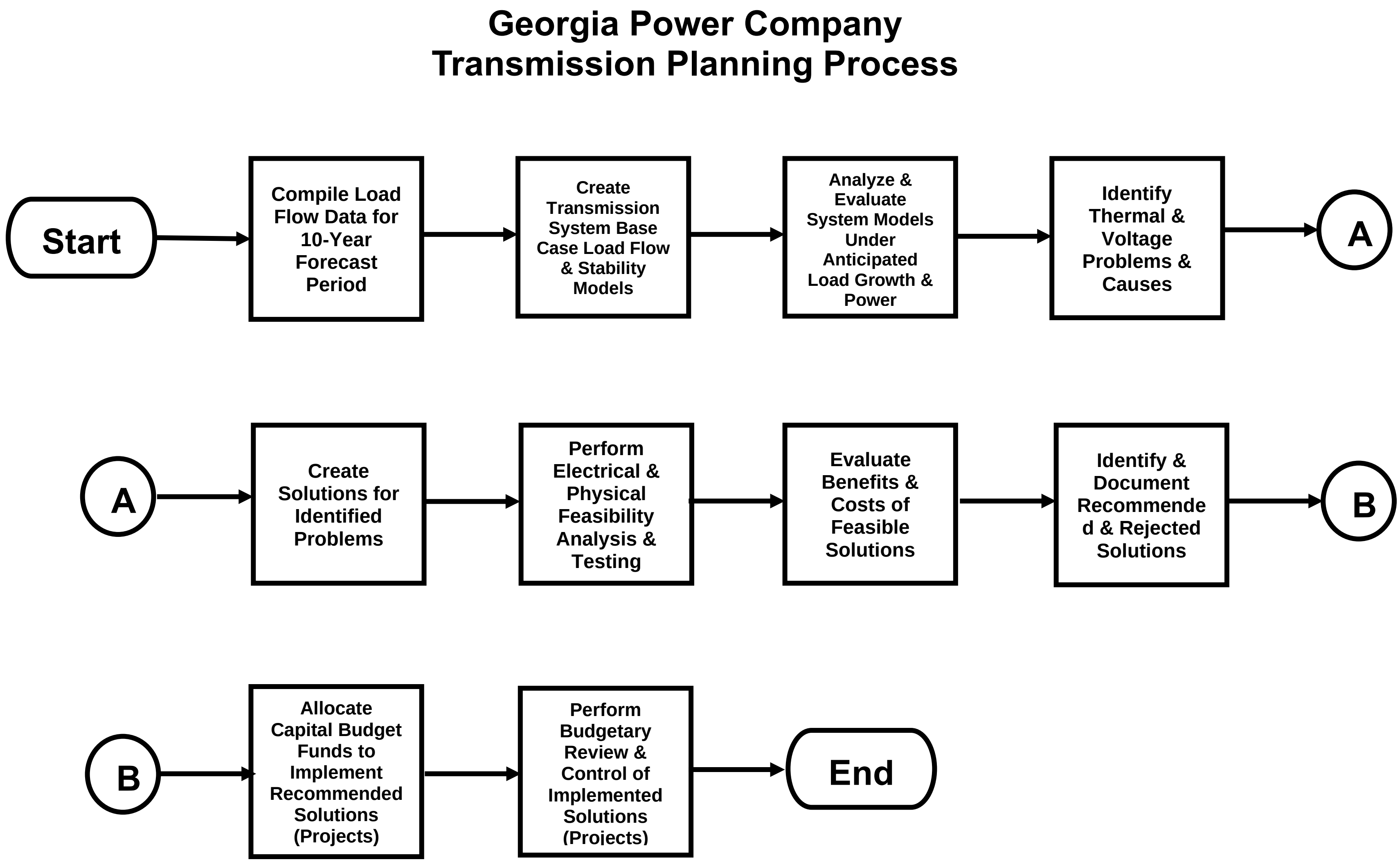
The PSS SINCAL program was developed by Siemens and is used to perform harmonics and unbalanced (three-phase) power flow studies. The program is used by transmission planners to evaluate the harmonic impact of adding shunt capacitors to the system to provide voltage support. Additionally, the program 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.

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.

<u>Long-term Focus on reducing resource uncertainties, costs, and delivery risks</u>

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 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).

<u>Reliable Firm Physical Transmission Service</u>
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.

<u>Economic Timing of Transmission Expansion Projects in Corrective Action Plans</u>
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 reliability 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 reliability 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.

<u>Steady State:</u> 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.

<u>Stability:</u> 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 is 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.

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

P2.3 – Internal breaker faults (non-Bus-tie Breaker) are simulated by modeling back-up breaker operation on either side of the failed breaker. The EHV and HV BES levels are evaluated separately consistent with Table 1 performance criteria. A list of non-bus-tie internal breaker faults modeled is provided in the study documentation.

P2.4 - Internal breaker faults on Bus-tie breakers are simulated by opening all breakers on the buses on either side of the Bus-tie. A list of bus-tie internal breaker faults modeled is provided in the study documentation.

P3 – Individual N-G cases developed for P1.1 category (generator outage) events are the starting point cases for subsequent single Contingency P3 event studies. The re-dispatch required as a result of the assumed generator outage is not performed as a system adjustment for the purpose of addressing System issues resulting from the individual generating unit assumed to be off-line. The system adjustment philosophy is described at the end of this section. In limited circumstances, if Non-Consequential load loss is used to address BES performance, the process described in TPL-001 Table 1 footnote 12 and Attachment 1- Stakeholder process will 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 02, 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 J. McDaniel 12/8/2021 F6896EB81B4045E... Will McDaniel – DU / Date
DocuSigned by: Chase Battaglio 12/8/2021 DC29DD094421447... Chase Battaglio – GPC / Date	DocuSigned by: J. Chris Weaver 12/8/2021 B08FE957613F48C... 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 E7340B646C4B4BE... 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	W R Seaton 4/12/00
Christopher D. Brewton - Dalton Utilities / Date	W. R. Seaton – Dalton Utilities / Date
Albert E. Hay 4/12/00	for Randy Kirkus 4/12/00
Albert E. Hay – GPC / Date	Randy W. Kirkus – GPC / Date
Seth W. Brown 4-12-00	for Greg Ford 4-12-00
Seth W. Brown – GTC / Date	Gregory S. Ford – GSOC / Date
Linda T. Gray 4-12-00	Larry G. Stephenson 4/12/00
Linda T. Gray – MEAG Power / Date	Larry G. Stephenson – MEAG Power / Date

[C]

TRANSMISSION SYSTEM OPERATIONS

[C1]

2024 SUMMER OPERATING STUDY

PUBLIC DISCLOSURE

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 2024:

1. 2024 Summer Peak Load Cases

A set of 2024 summer base cases was created using a modified dispatch of the generating units that were expected to be available for summer 2024.

The starting point for the study cases:
H = Shoulder (93% load)
S = Summer Peak (100% load)
T = Hot Weather (107% load)

Each S and H case has 4 versions:
NSEW = [redacted] MW North to South MISO Transfer, [redacted] MW FPL to Gulf Transfer
NSmaxEW = [redacted] MW North to South MISO Transfer, [redacted] MW FPL to Gulf Transfer
SNWE = [redacted] MW South to North MISO Transfer, [redacted] MW Gulf to FPL Transfer
SNmaxWE = [redacted] MW South to North MISO Transfer, [redacted] MW Gulf to FPL Transfer

Each version of case has two scenarios:
Renewables On = Solar generation, Biomass generation, and Grid-Charging Batteries On (Solar generation remains off in H cases)
Renewables Off = All Solar generation, Biomass generation, and Grid-Charging Batteries Off

To simulate peaking hour hydro capacity in Georgia during drought conditions (worst-case scenario), Transmission Operations provides guidance on how the hydro units should be modeled for all Summer Base Cases. The result for 2024 was a list of 10 hydro units running at their minimum with the remainder of hydro units either off or motoring (still providing VAR support).

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 that Transmission Operations has identified create a significant impact if offline jointly or units with possible common failure modes (such as a single equipment failure at West Point Dam). Specific unit-out cases are listed below.

3. West-East Flow Cases

Summer Peak and 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 economic dispatch, maintenance and other unexpected outages. Only SNWE and SNmaxWE scenarios were used for building these cases, as NSEW and NSmaxEW biased cases would be antagonistic.

Alabama:

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

Georgia:

- Bowen Units 1-4 on at minimum output, except for the S Renewables Off case as fully on
- Rocky Mountain offline
- Vogtle 3 & 4 at minimum output
- Gaston 1-4 at minimum output for Renewables Off cases
- Gaston 1-4 at maximum output for Renewables On cases
- Lindsay Hill running economically
- Hydro modeled at minimum flow
- Renewables On and Off still observed
- Warthen offline
- McIntosh 1-8 at minimum output for S cases
- McIntosh 1-5 at minimum output for H cases
- McDonough 3 offline
- Tenaska at minimum output for Renewable Off cases
- Tenaska at maximum output for Renewable On cases
- Talbot offline
- McManus offline

4. 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. Only NSEW and SNWE cases were used to build the Extreme Event cases. Max flow cases are deemed unrealistic when paired with an Extreme Event.

All of these cases were economically dispatched using Southern Company's Designated Network Resources for 2024 and the individual generating units' cost data.

SUMMER OPERATING STUDY ASSUMPTIONS

The following assumptions were used for the 2024 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 Tifton115 kV line.

Screening Procedure

1. SOS Load Flow Cases:
    - T cases: Renewables On/Off + NSEW, SNWE
    - H, S cases: Renewables On/Off + NSEW, NSmaxEW, SNWE, SNmaxWE
    - H, S cases above with additional single and multiple generator unit outages
    - Maximum West-East flow H, S cases: Renewables On/Off + SNWE, SNmaxWE
    - Special Extreme Event H, S cases: Renewables On/OFF + NSEW, SNWE

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, T cases
    - No element out using Rate B (95ºF ambient) in normal-weather peak, all H, S cases
    - Contingency N-1 (one element out) using Rate B (95ºF ambient), all H, S cases excluding Extreme Event cases
    - Contingency N-1 (one element out) using Rate B (95ºF ambient) in re-dispatched cases with one or more generation units out, all H, S cases excluding Extreme Event cases
    - Extreme Event contingencies using Rate B (95ºF ambient) in normal-weather peak

4. Unit Out Summary:

One Unit Off	**Case Name**
Basecase, no units out	NUO
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
McIntosh Unit 10 outage	MC10
Scherer Unit 1 outage	SCH1
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 Unit 1 and Unit 4 outage	BOW1BOW4
Bowen Unit 1 and McDonough Unit 6 outage	BOW1MCD6
Bowen Unit 1 and Scherer Unit 1 outage	BOW1SCH1
Bowen Unit 4 and Scherer Unit 1 outage	BOW4SCH1
Vogtle Unit 2 and Scherer Unit 1 outage	VOG2SCH1

5. Autobank Out Cases

Autobank	**Case Name**
[redacted]	

[redacted]

6. Extreme Events

Elements Out	Contingency Name
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
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PUBLIC DISCLOSURE

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

2024 Georgia Limiting Facilities
(Contingency Thermal Limitations)

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)

[redacted]

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

PUBLIC DISCLOSURE

CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII)

This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification.

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

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

PUBLIC DISCLOSURE

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[redacted]				

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[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

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[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

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Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

PUBLIC DISCLOSURE

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
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Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)

[redacted]

PUBLIC DISCLOSURE

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

PUBLIC DISCLOSURE

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Line or Transformer Name)	% Load	Contingency Event	Case Name	Recommended Operating Procedure(s)
[redacted]				

2024 Georgia Limiting Facilities
(Contingency Voltage Limitations)

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

PUBLIC DISCLOSURE

CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII)
This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification.
This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

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Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

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Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
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Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

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Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)

[redacted]

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Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

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Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

Monitored Facility (Bus)	Post Voltage	Contingency Name	Case Name	Recommended Operating Procedure(s)
[redacted]				

[C2]

2022 – 2024
SYSTEM PERFORMANCE

Major Outages

The table below lists the major outages for years 2022, 2023, and 2024 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]

PUBLIC DISCLOSURE

[redacted]

PUBLIC DISCLOSURE

[redacted]

[redacted]

[redacted]

PUBLIC DISCLOSURE

[redacted]

Major Event Summary

Major Event: [redacted]

Event Overview

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[D]

GEORGIA ITS

[D1]

GEORGIA ITS
TEN YEAR TRANSMISSION
EXPANSION PLAN
(2025 – 2034)

Georgia Projects

(Includes ITS & Savannah Projects)

2025 – 2034

Transmission Planning

Southern Company Services

FALL 2024

Southern Company

CONTENTS

I. GA ITS EXECUTIVE SUMMARY

The results of the studies performed on the GA ITS 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 start 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 constraints are reviewed by Georgia Power Transmission Operations. The transmission improvements are submitted to ITS Participants for ITS parity inclusion.

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.

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	5	163	12	543
230	26	211	37	530
115	7	49	10	69
Total	**38**	**423**	**59**	**1142**
Transmission Lines to be Rebuilt / Reconductored on Existing Right-of Way				
Voltage (kV)	Lines	Miles	Lines	Miles
500	0	0	0	0
230	24	239	33	310
115	57	479	78	672
Total	**81**	**718**	**111**	**982**
Transmission Lines Upgraded on Existing Right-of Way				
Voltage (kV)	Lines	Miles	Lines	Miles
500	0	0	0	0
230	1	26	1	26
115	1	14	1	14
Total	**1**	**40**	**1**	**40**
Transformers to be installed (low side ≥ 115kV)				
	Units		Units	
New	12		21	
Upgrade	4		10	
New Capacitor Banks to be Installed				
Voltage (kV)	Units	MVAR	Units	MVAR
230	0	0	0	0
115	2	75	5	165

	First 5 Years		Total 10 Years	
Total	**2**	**75**	**5**	**165**
New Series Reactors to be Installed				
Voltage (kV)	Units		Units	
230	2		6	
115	0		0	
New Static VAR Systems to be Installed				
Voltage (kV)	Units		Units	
230	1		1	
115	0		0	

A. Georgia ITS 10 Year Expansion Plan Projects List

Table 2 Georgia 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 Georgia ITS 10 Year Plan Project List

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
219	2025	19523	SAV: CC - HYUNDAI MOTORS SAVANNAH AKA. PROJECT EA	1/1/2025	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2025	18670	GTC: BANKS CROSSING - POND FORK 115 KV	5/1/2025	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2025	18492	MITCHELL - NORTH TIFTON 230KV RECONDUCTOR	5/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2025	19676	ADAMSVILLE - JACK MCDONOUGH 230KV LINE REBUILD	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2025	18800	ECHECONNEE-WELLSTON 115KV REBUILD	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2025	19187	GRID - BREMEN - CROOKED CREEK (APC) 115 KV PROJECT	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2025	18153	GTC: BONAIRE PRI-ECHECONNEE 115 KV PARTIAL REBUILD	6/1/2025	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
218	2025	20342	GTC: CAMDEN INDUSTRIAL PARK 230/115KV NEW SUBSTATION	6/1/2025	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2025	20590	GTC: EATONTON PRIMARY - LICK CREEK 115KV LINE SWITCH REPLACEMENT	6/1/2025	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
218	2025	11821	JESUP - LUDOWICI PRIMARY 115KV REBUILD	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2025	13753	MEAG: ALCOVY ROAD - SKC 115 KV RECONDUCTOR	6/1/2025	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2025	13787	MEAG: AULTMAN ROAD - BONAIRE PRIMARY 115 KV REBUILD	6/1/2025	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2025	20464	NORCROSS 230KV BUS 1-3 SERIES BUS TIE BREAKER INSTALLATION	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
216	2025	19631	PINE GROVE PRIMARY 115 KV DUAL STAGE CAPACITOR BANK	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2025	20067	SAV: DEPTFORD - MAGNOLIA 115KV RECONDUCTOR	6/1/2025	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2025	20466	SMART VALVE INSTALLATION	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
218	2025	21046	THALMANN AND COLERAIN 23O KV LINE RELAY PANEL UPGRADES	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2025	20431	VILLA RICA LOW SIDE BREAKER	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
218	2025	20684	CAMDEN INDUSTRIAL PARK (GPC)	6/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2025	18774	GTC: HEARD COUNTY - TENASKA 500KV (SECOND LINE)	12/1/2025	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2025	18889	JEFFERSON STREET#3 - NORTHWEST (WHITE) 115 KV RECONDUCTOR	12/1/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2025	20326	ANTHONY SHOALS STATCOM SYSTEM	12/31/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2025	20152	CC - CASS PINE- HILL VIEW 230 KV LINE- CC IMPROVEMENTS	12/31/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2025	20175	CC - PROJECT CHRONOS-SK/HYUNDAI	12/31/2025	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2025	20010	GTC: ANTHONY SHOALS - WASHINGTON 115 KV LINE REBUILD	12/31/2025	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2025	17075	SAV: LITTLE OGEECHEE 230-115KV: RELAY MODERNIZATION	12/31/2025	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2026	18691	GTC: LIZARD LOPE - WESTOVER 115 KV NEW LINE	3/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	20018	CC - QTS FAYETTEVILLE TRANSMISSION NEEDS	4/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
208	2026	19597	ADAMSVILLE - BUZZARD ROOST 230KV REBUILD AND JUMPER UPGRADE	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2026	18960	BLANKETS CREEK – WOODSTOCK 115KV LINE REBUILD	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2026	20243	CC - GARRETT ROAD SWITCHING STATION - TRAE LANE	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	20216	CC - STONEWALL TELL ROAD (TA REALTY)	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2026	18679	DU: EAST DALTON - OOSTANAULA 115KV REBUILD	6/1/2026	DU	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	20491	EAST POINT RELAY MODERNIZATION	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2026	16007	FENWICK STREET - SAND BAR FERRY 115KV (RECONDUCTOR/REBUILD)	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2026	20516	GOAT ROCK 230KV SWITCH, JUMPER, & LINE TRAP REPLACEMENT	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2026	19618	GORDON-N DUBLIN 115KV (GORDON-ENGL MCI J) REBUILD	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2026	21139	GRADY - MORROW (WHITE) 115KV REBUILD	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2026	20474	GRADY 230/115KV RELAY MODERNIZATION	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2026	19706	GRID - GAINESVILLE #2 EQUIPMENT REPLACEMENT	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2026	21137	GTC: CONYERS - CORNISH MOUNTAIN 115KV LINE UPGRADE	6/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2026	19334	GTC: LAGRANGE - NORTH OPELIKA 230 KV	6/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2026	20015	GTC: MORNING HORNET 2ND 230/115 KV BANK & THUMBS UP 115KV TL	6/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2026	19999	GTC: ROBINS SPRING BUS REPLACEMENT	6/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2026	20001	GTC: ROBINS SPRING CAPACITOR BANK INSTALLATION	6/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2026	19636	HAMMOND - WEISS DAM 115KV LINE REBUILD	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2026	20512	KATHLEEN AREA IMPROVEMENTS	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2026	20490	KLONDIKE RELAY MODERNIZATION	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2026	19598	MEAG: DRESDEN - LAGRANGE PRIMARY 230KV UPGRADE & JUMPERS	6/1/2026	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2026	20270	MEAG: RAY PLACE RD - WASHINGTON #3	6/1/2026	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2026	20271	MEAG: RAY PLACE RD - WASHINGTON (WASHINGTON - WASHINGTON 3)	6/1/2026	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	20300	MORROW 115KV RELAY UPGRADE	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2026	18690	PALMYRA REACTOR REMOVAL	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2026	20066	SAV: BOULEVARD - DEPTFORD 115KV RECONDUCTOR	6/1/2026	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2026	19966	SAV: CC - BIG OGEECHEE 500/230KV (CC NETWORK IMPROVEMENTS)	6/1/2026	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2026	20277	SAV: MCINTOSH - PURRYSBURG 230KV REACTORS	6/1/2026	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2026	20489	SCOTTDALE RELAY MODERNIZATION	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	17900	UNION CITY - YATES 230 KV WHITE LINE REBUILD	4/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
208	2026	20691	UNION CITY - YATES 230KV (WHITE) SWITCH AND TRAP REPLACEMENT	6/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2026	20223	CC - PROJECT PAYTON BAINBRIDGE	6/30/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	21022	OHARA BREAKER REPLACEMENT	10/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	20668	DRESDEN LINE PROTECTIVE RELAYING	12/1/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2026	20874	GTC: BARNESVILLE PRIMARY-BARNESVILLE #1 115KV RECONDUCTOR	12/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	20273	GTC: DRESDEN 500KV BUS EXPANSION	12/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2026	20002	GTC: GORDON - SANDERSVILLE #1 115KV LINE REBUILD	12/1/2026	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2026	20151	CC - CASS PINE 230/25 NEW SUB - QCELLS - CC IMPROVEMENTS	12/31/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2026	19287	GRADY-WEST END 115KV REBUILD	12/31/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2026	19363	MORROW - MOUNTAIN VIEW 115 KV REBUILD	12/31/2026	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2027	18832	MEAG: FORTSON 230KV SUBSTATION MODERNIZATION	1/13/2027	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2027	20509	CC - EMBLEM RIVERSIDE CUSTOMER SUB (FLEXENTIAL)	3/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2027	19635	GTC: HICKORY LEVEL - VILLA RICA 230KV LINE RECONDUCTOR	5/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2027	19601	MORROW - YATES COMMON 115KV LINE UPGRADE	5/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2027	15879	POSSUM BRANCH - YATES COMMON 115KV REBUILD (YATES TO CLEM)	5/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
208	2027	20771	CC - GULLATT ROAD TRANSMISSION IMPROVEMENTS	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2027	18736	CC - MICROSOFT - SHUGART (CCO06)	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2027	20781	CC - SUMMER LAKE - VILLA RICA 230KV REBUILD (CC IMPROVMNT)	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2027	20736	CC - TA REALTY ELLENWOOD NETWORK IMPROVEMENTS	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2027	20234	DOYLE - LG&E MONROE 230KV - JACKS CREEK LOOP IN	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2027	20858	GTC: ADAMSVILLE - BUZZARD ROOST 230KV REBUILD	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2027	20776	GTC: DOUGLASVILLE - VILLA RICA 230KV REBUILD (CC IMPROVEMENT)	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2027	20778	GTC: DOYLE - WINDER PRIMARY 230KV LINE JUMPER REPLACEMENT	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2027	19358	GTC: EAST MOULTRIE - HIGHWAY 112 230 KV LINE	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2027	09662	GTC: EAST WALTON 500/230KV PROJECT	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2027	20505	GTC: GARRETT RD - V. RICA 230KV LINE RECONDUCTOR (CC NET IM)	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2027	19622	GTC: RIDDLEVILLE BUS REPLACEMENT	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2027	19606	GTC: SKC 115KV BUS AND JUMPER REPLACEMENT	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2027	20020	GTC: SOUTH HAZLEHURST - NEW LACY 230KV LINE	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2027	20506	GTC: SWITCH WAY - THORNTON ROAD 230KV LINE REBUILD	6/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
218	2027	18668	JESUP - OFFERMAN 115KV REBUILD	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
202	2027	10143	LAWRENCEVILLE - WINDER 115KV LINE REBUILD	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2027	10481	LAWRENCEVILLE - WINDER PRIMARY 230KV LINE REBUILD	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2027	20264	MEAG: RAY PLACE RD - WARRENTON PRIMARY	6/1/2027	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2027	19248	SANDERSVILLE #1 - WADLEY PRI. 115KV REBUILD/RECONDUCTOR	6/1/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2027	20785	SAV: GOSHEN (SAV) - KRAFT 115KV LINE REBUILD	6/1/2027	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2027	20065	SAV: GOSHEN (SAV) - MCINTOSH 115KV LINE REBUILD	6/1/2027	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2027	20717	CC - TOMOCHICHI 500/230KV SOLUTION (CC NETWORK IMPROVEMENTS)	7/15/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2027	18573	GRID - ARKWRIGHT - LLOYD SHOALS 115KV	7/30/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2027	20591	GTC: EATONTON PRIMARY (035591) - LICK CREEK 115KV REBUILD	12/1/2027	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2027	17977	ATHENA - EAST WATKINSVILLE 115 KV (REBUILD)	12/31/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2027	20150	CC - HILL VIEW & GRASSY HOLLOW SUB - CC IMPROVEMENTS	12/31/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2027	20024	DYER ROAD - EAST ROANOKE 115KV (REBUILD)	12/31/2027	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2028	19997	AULTMAN ROAD-PERRY 115KV LINE REBUILD	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2028	20797	CC - EAST VILLA RICA AREA SWITCHING STATION (CC IMPROVEMENT)	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2028	20774	CC - VILLA RICA UPGRADES (CC NETWORK IMPROVEMENTS)	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2028	21048	FITZGERALD - PITTS 115 KV LINE REBUILD	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2028	08458	GTC: BARNESVILLE - SOUTH GRIFFIN 230KV PROJECT	6/1/2028	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2028	20503	GTC: BARNEYVILLE - EAST MOULTRIE 115KV NEW LINE	6/1/2028	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2028	20873	GTC: BONAIRE PRIMARY 500/230KV XFMR REPLCMNT & RELAY MOD	6/1/2028	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2028	19992	GTC: BOSTWICK - EAST SOCIAL CIRCLE 230KV RECONDUCTOR	6/1/2028	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2028	20777	JACK MCDONOUGH - NORTHWEST (BLACK) 230KV RECONDUCTOR	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2028	19629	MEAG: BRUMBLEY CREEK - SOUTH BAINBRIDGE 115KV REBUILD	6/1/2028	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2028	19630	MEAG: THOMASVILLE 230/115KV AUTOBANK REPLACEMENT	6/1/2028	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2028	20482	PITTMAN ROAD - WEST POINT DAM (USA) 115KV REBUILD	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2028	20656	PLANT YATES BREAKER AND HALF STATION	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2028	20783	SAV: COLEMAN - DEAN FOREST 115KV LINE REBUILD	6/1/2028	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2028	20407	SAV: MAGNOLIA - TRUMAN PARKWAY 115KV REBUILD	6/1/2028	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2028	21069	SMART VALVES AT EAST VILLA RICA SWITCHING STATION	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2028	20768	SOUTH MACON 115KV BUSES 1 & 2 REPLACEMENT	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2028	20274	UNION CITY - YATES 230KV (BLACK) LINE REBUILD	6/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2028	13166	FIRST AVENUE - NORTH COLUMBUS 115KV LINE REBUILD	12/1/2028	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2028	20586	GTC: NORTH DUBLIN 230/115KV TRANSFORMERS AND BUS-TIE BREAKER	12/1/2028	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2029	21062	ASHLEY PARK-WANSLEY 500KV	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2029	10222	BLAKELY PRIMARY - HUCKLEBERRY 115KV REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2029	21047	BROADWAY - ECHECONNEE 115 KV LINE REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2029	16887	BUTLER - THOMASTON 230KV LINE CONVERSION	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2029	21036	BUZZARD ROOST - FACTORY SHOALS 230KV NEW LINE	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2029	21142	CONYERS - KLONDIKE 230 KV SECOND LINE	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2029	21138	GLENWOOD SPRINGS - PORTERDALE PRIMARY 230KV LINE SWITCH REPL	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2029	21112	GTC: BARNESVILLE PRIMARY - THOMASTON 230KV	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2029	10814	GTC: BAY CREEK 230/115KV SECOND AUTO TRANSFORMER	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2029	21140	GTC: BONAIRE PRIMARY - EASTMAN PRIMARY 115 KV LINE REBUILD	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2029	20849	GTC: CLIFTONDALE - LINE CREEK 230KV LINE	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2029	19950	GTC: DRESDEN - TALBOT 500KV LINE	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2029	20760	GTC: HOPEWELL 230/115 KV BANK A	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2029	21123	GTC: TENASKA - WANSLEY 500KV NEW LINE	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
206	2029	21141	LLOYD SHOALS - PORTERDALE PRIMARY 115KV REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2029	20285	LOWER RIVER - WEBB (APC) 115KV RECONDUCTOR	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
212	2029	19621	MCEVER ROAD - SHOAL CREEK 115KV REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
218	2029	20346	MCMANUS - WEST BRUNSWICK 115KV REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2029	17706	MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV REBUILD	6/1/2029	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2029	11051	MEAG: SLAPPEY DRIVE - WESTOVER 115KV LINE REBUILD	6/1/2029	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2029	20757	NORCROSS - NORTH DRUID HILLS 115KV REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2029	21006	SAV: BOULEVARD - MAGNOLIA 115 KV LINE REBUILD	6/1/2029	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2029	21023	SAV: DEAN FOREST - LITTLE OGEECHEE 230 KV REBUILD	6/1/2029	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2029	20989	SAV: RICE HOPE NEW AUTO TRANSFORMER	6/1/2029	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2029	13628	SOUTH BAINBRIDGE - SINAI (FPL) 115KV LINE RECONDUCTOR	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2029	20248	BAY CREEK - CONYERS 230KV REBUILD	12/31/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2030	21129	ANNISTON - HAMMOND 230KV LINE	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	20764	ATKINSON - NORTHSIDE DRIVE 115KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	20761	ATKINSON - NORTHWEST 115KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	21130	CC - NORTH GEORGIA DATA NETWORK UPGRADES	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	10478	CORNELIA - TALLULAH LODGE 115KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	18669	DU: DAWSON CROSSING - NELSON (WHITE) 115 KV REBUILD	6/1/2030	DU	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	21097	EAST POINT - TRIBUTARY 230KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
208	2030	20480	EAST POINT - UNION CITY 230KV BLACK LINE RECONDUCTOR	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2030	19627	ECHECONNEE-WELLSTON 115KV LINE REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2030	21063	FARLEY (APC)-TAZEWELL 500KV	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	12120	GAINESVILLE #2 - MCEVER ROAD 115 KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2030	20298	GLENWOOD SPRINGS - LAKE OCONEE 115KV LINE REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2030	21128	GOAT ROCK REACTORS INSTALLATION	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2030	19996	GOLDENS CREEK - WARRENTON PRIMARY 230KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2030	20428	GORDON-SANDERSVILLE #1 115KV LINE REBUILD (DEEPSTEP-SAND #6)	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2030	21116	GOSHEN AREA STRATEGIC SOLUTION	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2030	21073	GTC: BIG SMARR - TOMOCHICHI 500KV	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	21014	GTC: BUZZARD ROOST - CAVENDER DRIVE 230KV NEW LINE	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	21013	GTC: CAVENDER DRIVE 500/230KV AUTOBANK	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	20375	GTC: EAST WATKINSVILLE 230 KV STATION MODIFICATION	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	21111	GTC: HARTWELL DAM - HARTWELL ENERGY 230KV SERIES REACTORS	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	21113	GTC: HARTWELL ENERGY - MIDDLE FORK 230KV LINE	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	21131	GTC: POND FORK - MIDWAY 115KV LINE	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2030	21077	GTC: ROCKVILLE - TIGER CREEK -WARTHEN 500KV LINES	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2030	21076	GTC: TALLBOT #2 - TAZEWELL 500KV LINE	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2030	21094	GTC: TIGER CREEK-ROCKVILLE-NORTH SPA 230KV PROJECT	6/1/2030	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	20789	JEFFERSON ROAD - WINDER PRIMARY 115KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2030	20284	KETTLE CREEK PRIMARY - PINE GROVE PRIMARY 115KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2030	21118	MEAG: ATHENA - WARRENTON 230KV CONVERSION	6/1/2030	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	20857	NEW CAVENDER DRIVE - TRIBUTARY 230KV LINE	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2030	21093	NORTH SPA 230KV STRATEGIC PROJECT	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2030	19995	TALLULAH LODGE - TOCCOA 115 KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	2030	21098	TRIBUTARY - THORNTON RD 230KV REBUILD	6/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2030	20160	THOMASTON 230 NEW BUILD SUB	11/1/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2030	18848	BAINBRIDGE TRANSMISSION: EAST RIVER ROAD, EAST BAINBRIDGE	12/31/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2030	19626	GLENWOOD SPRINGS 115KV CAP BANK	12/31/2030	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	2031	20690	EAST POINT - UNION CITY (WHITE) 230KV REBUILD	5/1/2031	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2031	19632	AVERY - HOPEWELL 115KV RECONDUCTOR	6/1/2031	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
211	2031	10811	BOWEN #10 500/230KV AUTOBANK REPLACEMENT	6/1/2031	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2031	20756	HATCH - WADLEY 500 KV LINE STRATEGIC PROJECT	6/1/2031	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
214	2031	21099	MEAG: PIO NONO 230/115KV AREA SOLUTION	6/1/2031	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	2032	21114	MEAG: SOUTH GRIFFIN 230/115KV BANK #5	6/1/2032	MEAG	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2032	20784	SAV: COLEMAN - MELDRIM 115KV LINE REBUILD	6/1/2032	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	2033	20767	ARKWRIGHT BUS AND JUMPER REPLACEMENT	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
202	2033	20758	BAY CREEK - CONYERS 230KV LIMITING ELEMENT REPLACEMENT	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2033	20793	EVANS PRIMARY - THURMOND DAM (USA) #5 115KV REBUILD	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2033	20794	EVANS PRIMARY - THURMOND DAM (USA) #6 115KV REBUILD	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	12217	GTC: CENTER PRIMARY - CLARKSBORO 230 KV REBUILD	6/1/2033	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	20773	GTC: CLARKSBORO - WINDER PRIMARY 230KV REBUILD	6/1/2033	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	12147	GTC: EAST SOCIAL CIRCLE - SNELLVILLE 230KV EQUIPMENT UPGRADE	6/1/2033	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	21075	GTC: EAST WALTON - MIDDLE FORK 500KV	6/1/2033	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	20791	GTC: SHOAL CREEK - SOUTH HALL 230KV REBUILD	6/1/2033	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	21053	MCEVER ROAD - SHOAL CREEK 115KV REBUILD PHASE III	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2033	09661	MCGRAU FORD - MIDDLE FORK 500KV LINE PROJECT	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2033	20796	SAV: MELDRIM BANK D REPLACEMENT	6/1/2033	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2033	14222	THOMSON PRIMARY 230/115KV SECOND TRANSFORMER	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

Zone	Year	TEAMS Number	Project Name	Need Date 2024	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Totals
202	2033	20759	WINDER PRIMARY 230KV BUS 1-2 PARALLEL BUS-TIE INSTALLATION	6/1/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	2033	10487	PINE GROVE PRIMARY - WEST VALDOSTA 115 KV RECONDUCTOR	12/31/2033	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	2034	18700	DAWSON CROSSING - GAINESVILLE #1 115 KV	6/1/2034	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	2034	20787	SAV: LITTLE OGEECHEE 230/115KV BANK REPLACEMENT	6/1/2034	SAV	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	2034	17993	EVANS PRIMARY - THOMSON PRIMARY 115KV REBUILD	12/31/2034	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Total						**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

B. 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	Project Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Estimated Cost – ITS Assigned	Totals
214	12016	ARKWRIGHT - LLOYD SHOALS 115 KV LINE RECONDUCTOR	6/1/2024	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
216	19628	ARLINGTON PRIMARY - LIZARD LOPE 115KV RECONDUCTOR	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
212	20477	BANKS CROSSING - CENTER PRIMARY (BLACK) 230 KV LINE	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
201	12063	DOUGLASVILLE - POST RD 115KV REBUILD	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	19623	GTC: AUGUSTA CORPORATE PARK - VOGTLE 230KV REBUILD	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
214	20513	GTC: BIG GROCERY-WESTLAKE ROAD 230KV PROJECTS	6/1/2029	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
219	15228	KRAFT 230/115KV TRANSFORMER RATING INCREASE	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
208	20000	YATES 6 AND 7 230KV LIMITING ELEMENT REPLACEMENT	6/1/2029	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
213	20482	PITTMAN ROAD - WEST POINT DAM (USA) 115KV REBUILD	6/1/2031	GPC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
215	20266	GTC: GOSHEN - VOGTLE 230KV REBUILD	6/1/2031	GTC	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**

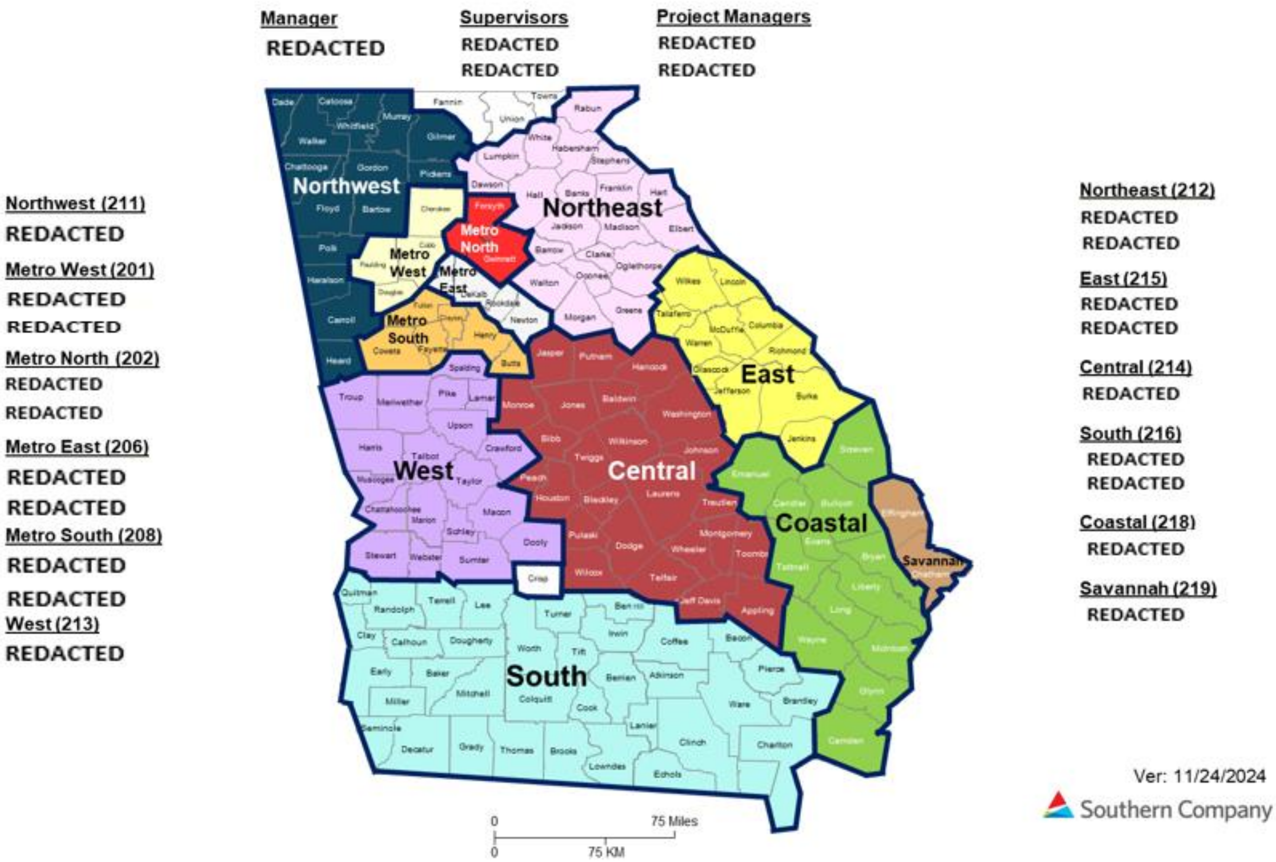
C. Completed Projects List – Removed from the Current 10 Year Expansion Plan

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
214	20017	ARKWRIGHT - SOUTH MACON (BLACK) 115KV LINE REBUILD	6/1/2024
213	18671	CORN CRIB - LAGRANGE 115KV LINE REBUILD	6/1/2024
212	19340	GTC: MIDDLE FORK STATCOM SYSTEM	6/1/2024
218	19028	KINGSLAND BANK C REPLACEMENT	6/1/2024
206	18104	KLONDIKE SWITCH REPLACEMENT	6/1/2024
211	19305	MCGRAU FORD STATCOM SYSTEM	6/1/2024
202	20006	NORCROSS 230KV BUS 2-3 SERIES BUS TIE BREAKER INSTALLATION	6/1/2024
216	19019	PINE GROVE PRIMARY BANK B REPLACEMENT	6/1/2024
215	14271	THOMSON PRI - WARRENTON PRI 115KV WHITE LINE REBUILD	6/1/2024
215	19625	WARRENTON PRIMARY 230KV SWITCHES AND JUMPER REPLACEMENT	6/1/2024
211	19341	GTC: JUDY MOUNTAIN SHUNT REACTOR	12/1/2024
208	20021	GTC: UNION CITY 230KV BUS TIE	12/1/2024
211	20430	EAST DALTON JUMPER REPLACEMENT	6/1/2025

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 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-001-5 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.

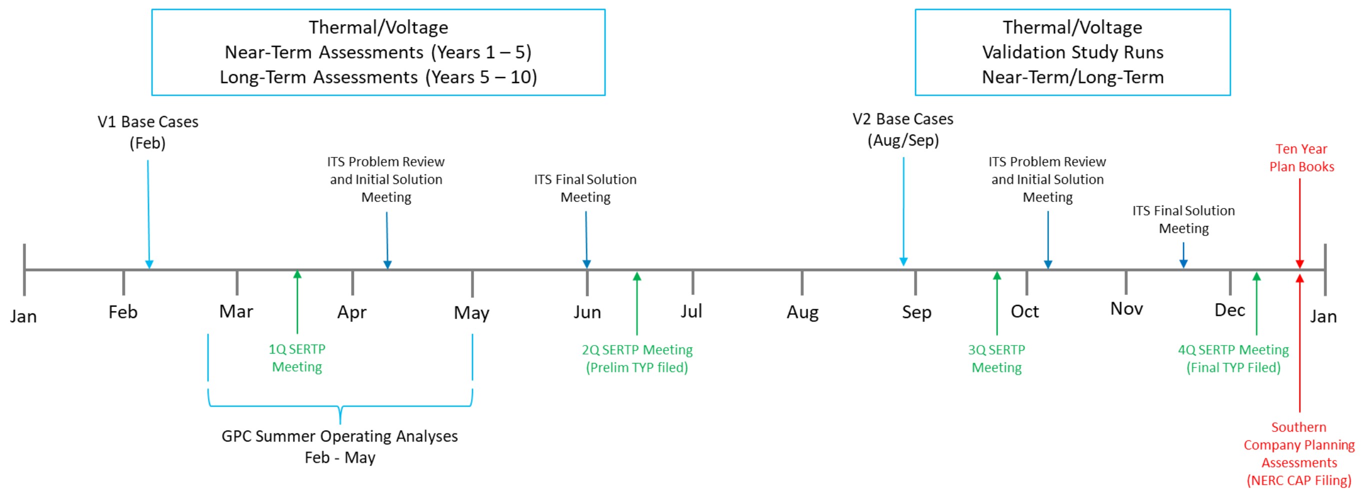
Maintaining System Models

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 the NERC MOD-032 standard, 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 (MMWG) 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 Attachment 1 of the MOD-032 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 by each Load Serving Entity within the Southern Balancing Authority Area (SBAA).
5. Known commitments for Firm Transmission Service and Interchange.
6. Resources required for Load.

The model of the SBAA is constantly changing. The 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 2024 Series ITS Load Forecast

REDACTED

Figure 3 Total 2024 Series ITS Summer Coincident Load Forecast

REDACTED

Generation

Another key modeling assumption made in case development is the 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 both owned units and Power Purchase 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-001-5 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, except a summer peak scenario, 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 6 Steady State Transmission Planning Criteria below briefly describes the Transmission Planning steady state study methodology to meet TPL-001-5 Table 1 Contingency requirements:

Table 6 Steady State Transmission Planning Criteria (TPL-001-5 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 is 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 6 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 VI B, Generation Assumptions. This table shows not only the units considered but the cases in which they were used as well. Some unit outs were not needed in certain cases because the unit was already off due to the expected dispatch in the case. These selected generating units which provide more severe stress on the system have been identified through experience over many years of conducting power flow analysis based upon their relative size, location, or other factors.

Steady State Sensitivity Analysis

The Standard requires additional Sensitivity Studies to be performed to demonstrate the impact of changes to the basic assumptions used in the base cases. The sensitivity selected was the availability of hydroelectric generation. This sensitivity was evaluated utilizing the criteria described in TPL-001-5 Table 1. The analysis was performed on all years of the Near-Term and Long-Term Planning Horizons using Off-Peak conditions with the availability of hydroelectric generation and on System Shoulder conditions, which represent 93% of System peak and the unavailability of hydroelectric generation. [Requirement 2 Part 2.1.4]

Steady State Equipment Sparing Analysis

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

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 B, Stability Project Details.

Table 7 Stability Transmission Planning Performance briefly describes the Transmission Planning stability study methodology to meet TPL-001-5 Table 1 performance requirements:

Table 7 Stability Transmission Planning Performance Requirements (TPL-001-5 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 inTPL-001-5 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-001-5 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 inTPL-001-5 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 (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	Studies were performed with a Transmission element (P6.1 and P6.2) out of service at generating plants on the System. Then a three-phase, normally cleared fault was studied on another element at the generating plant. If the generators are not stable for this contingency, then a System adjustment or a CAP project was implemented to make sure that the generation remained stable. Faults on shunt devices (P6.3) were not as severe because tripping a shunt device does not result in weakening the System as compared to tripping a transmission line or transformer. Thus, P6.3 was not explicitly studied.
		1. Transmission Circuit		
		2. Transformer		
		3. Shunt Device		
		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:	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.
		1. Any two adjacent (vertically or horizontally) circuits on common structure		
		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, local generation was increased to maximum output.
- For System peak load cases, the percentage of induction motor load that was modeled at each bus with a dynamic load model was increased.

For the studies in which an area generator output sensitivity was 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-001-5 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 C, 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 Participants 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 base 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 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 interface's transfer capability limitations and resulting projects are detailed in a report that is provided to Transmission Planning for inclusion in the results of this document.

The interfaces of the SBAA are evaluated annually as part of the transmission planning process. The analysis is performed to ensure that the Southern Balancing Authority can meet 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 D, Interface Transfer Capability Project Details.

Northern Interface

For the Northern interfaces of MISO, TVA, Duke Energy, Santee Cooper, and Dominion Energy – South Carolina, 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 consider 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 multiple companies 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.” It is important to note that the Florida interface is fundamentally radial from the SBAA and the transmission facilities in the connecting balancing authorities have a high-level of interdependence. To ensure the most conservative screens are performed, impacts from “netting” are considered in the same manner as the Northern Interface.

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 8 Thermal and Voltage Operating Guides

Line Name (Breaker to Breaker)	OG Start Date	OG End Date	Operating Guide Procedure
Albany Area Operating Guide	6/1/2029	6/1/2030	**REDACTED**
Americus - Thrill Hill 115kV Operating Guide	6/1/2025	6/1/2030	**REDACTED**
Anniston - Hammond 230kV Operating Guide	6/1/2029	6/1/2030	**REDACTED** **REDACTED**
Arkwright - Forrest Road 115KV Operating Guide (Pre-Contingency)	6/1/2027	6/1/2028	**REDACTED** **REDACTED**
Arkwright-Lloyd Shoals 115kV line Operating Guide (Pre-Contingency)	6/1/2025	6/1/2026	**REDACTED** **REDACTED**
Arlington Area 115kV Operating Guide	6/1/2029	6/1/2030	**REDACTED** **REDACTED**
Athena - Union Point Primary 115kV Operating Guide	6/1/2026	6/1/2027	**REDACTED** **REDACTED**
Atkinson - Northside Dr 115kV Operating Guide	6/1/2028	6/1/2030	**REDACTED** **REDACTED**
Atkinson – Northwest 115kV Operating Guide	6/1/2028	6/1/2030	**REDACTED**
Augusta Corporate Park - Vogtle 230kV Operating Guide	6/1/2026	6/1/2027	**REDACTED**
Aultman Road-Perry 115kV Operating Guide (Pre-Contingency)	6/1/2027	6/1/2029	**REDACTED**
Avalon Junction - Pooles Creek - Bio 115kV Operating Guide	6/1/2025	6/1/2029	**REDACTED** **REDACTED**
Banks Crossing - Pond Fork 115kV Operating Guide	6/1/2025	6/1/2026	**REDACTED**

Line Name (Breaker to Breaker)	OG Start Date	OG End Date	Operating Guide Procedure
Barnesville Primary - South Griffin 115kV Operating Guide	6/1/2025	6/1/2027	REDACTED
Barnesville Primary - Thomaston 230kv Operating Guide (Pre-Contingency)	6/1/2029	6/1/2030	REDACTED
Baxley - Jesup 115kV Operating Guide	6/1/2025	12/31/2025	REDACTED REDACTED
Bay Creek - Conyers 230kV Operating Guide	6/1/2025	6/1/2027	REDACTED REDACTED
Bay Creek - Monroe 115kV Operating guide	6/1/2027	6/1/2029	REDACTED REDACTED
Bay Creek - Moon Road 115kV Operating Guide	6/1/2026	6/1/2027	REDACTED REDACTED
Bio - Center Primary 230kV Operating Guide	6/1/2025	6/1/2030	REDACTED REDACTED REDACTED
Blankets Creek - Woodstock 115 kV Operating Guide (Pre-Contingency)	6/1/2025	6/1/2026	REDACTED
Branch - Tiger Creek (Black) 230KV Operating Guide	6/1/2026	6/1/2027	REDACTED REDACTED
Branch - Tiger Creek (White) 230KV Operating Guide	6/1/2026	6/1/2027	REDACTED REDACTED
Cartersville - Hill View 230kV Operating Guide	6/1/2027	6/1/2028	REDACTED
Center Primary - Commerce Primary 115kV Operating Guide (pre-contingency)	6/1/2027	6/1/2029	REDACTED REDACTED
Conyers - Klondike 230kV Operating Guide	6/1/2026	6/1/2027	REDACTED
Corn Crib - Lagrange 115kV Operating Guide	6/1/2028	6/1/2029	REDACTED REDACTED
Cornelia - Tallulah Lodge 115kV Operating Guide	6/1/2028	6/1/2029	REDACTED
Daisy - West Valdosta Operating Guide	6/1/2025	6/1/2027	REDACTED
Dawson Crossing - Gainesville #1 Operating Guide	6/1/2026	6/1/2027	REDACTED REDACTED REDACTED REDACTED
Dawson Crossing - Nelson (White) 115kV Operating Guide	6/1/2025	6/1/2029	REDACTED REDACTED REDACTED REDACTED REDACTED
Dresden - LaGrange 230kV Operating Guide	6/1/2028	6/1/2029	REDACTED REDACTED
East Social Circle - East Watkinsville 230kV Operating Guide	6/1/2027	6/1/2028	REDACTED REDACTED
East Watkinsville - Russel Dam 230kV Operating Guide	6/1/2025	6/1/2029	REDACTED REDACTED REDACTED

Line Name (Breaker to Breaker)	OG Start Date	OG End Date	Operating Guide Procedure
East Watkinsville 230/115kV Bank A Operating Guide	6/1/2025	6/1/2027	REDACTED
Eatonton AB - Newborn Rd 230KV Operating Guide	6/1/2028	6/1/2029	REDACTED
Evans Primary - Thomson Primary 115kV Operating Guide	6/1/2025	6/1/2027	REDACTED REDACTED
First Avenue - North Columbus 115kV Operating Guide (Pre-Contingency)	6/1/2026	6/1/2030	REDACTED REDACTED
Fortson - Lagrange 230kV Operating Guide	6/1/2025	6/1/2028	REDACTED REDACTED REDACTED REDACTED
Fortson - Talbot 230kV Operating Guide	6/1/2029	6/1/2030	REDACTED
Fortson - Goat Rock 230kV (White) Operating Guide	6/1/2029	6/1/2030	REDACTED REDACTED
Fortson - Goat Rock 230kV (Black) Operating Guide	6/1/2029	6/1/2030	REDACTED REDACTED
Gainesville #2 - McEver Road 115kV Operating Guide	6/1/2029	6/1/2030	REDACTED REDACTED
Glenwood Springs 321318 – Lake Oconee 115kV Operating Guide	6/1/2025	6/1/2029	REDACTED REDACTED
Gordon-North Dublin 115kV Operating Guide (Pre-Contingency)	6/1/2025	6/1/2026	REDACTED
Goshen - Vogtle 230kV Operating Guide	6/1/2026	6/1/2027	REDACTED
Hercules - Porterdale Primary 115kV Operating Guide (Pre-Contingency)	6/2/2026	6/2/2027	REDACTED REDACTED
Jefferson Road - Winder Primary 115kV Operating Guide	6/1/2027	6/1/2029	REDACTED REDACTED
Jonesboro - Ohara 230kV Operating Guide	6/1/2025	6/1/2027	REDACTED REDACTED
Kathleen 230/115kV Operating Guide	6/1/2027	6/1/2028	REDACTED REDACTED
Kawikee - South Columbus 115kV Operating Guide	6/1/2029	6/1/2030	REDACTED
Kettle Creek Primary - Pine Grove Primary 115kV Operating Guide (Pre-Contingency)	6/1/2025	6/1/2030	REDACTED REDACTED REDACTED
Klondike - Scherer 500kV Operating Guide	6/1/2026	6/1/2027	REDACTED REDACTED
Kraft 230/115 kV Bank B Operating Guide	6/1/2025	6/1/2029	REDACTED REDACTED REDACTED
Lizard Lope Area 115kV Operating Guide	6/1/2029	6/1/2030	REDACTED
Lloyd Shoals - Porterdale Primary 115kV Operating Guide	6/1/2026	6/1/2027	REDACTED REDACTED
Lloyd Shoals - Porterdale Primary 115kV Operating Guide (Pre-contingency)	6/1/2025	6/1/2029	REDACTED REDACTED
McDonough - South Griffin 115kV Operating Guide	6/1/2027	6/1/2028	REDACTED REDACTED
McEver Road - Shoal Creek 115kV Operating Guide (Pre-Contingency)	6/1/2026	6/1/2029	REDACTED REDACTED

Line Name (Breaker to Breaker)	OG Start Date	OG End Date	Operating Guide Procedure
Mcintosh 230/115 kV Bank A Operating Guide	6/1/2028	6/1/2029	**REDACTED**
McManus - West Brunswick 115 kV Operating Guide	6/1/2026	6/1/2028	**REDACTED** **REDACTED**
Mitchell - North Tifton 230kV Operating Guide	6/1/2025	6/1/2025	**REDACTED** **REDACTED**
Mitchell - Raccoon Creek 230kV Operating Guide	6/1/2025	6/1/2030	**REDACTED** **REDACTED**
Raccoon Creek - Scooter 230kV Operating Guide	6/1/2025	6/1/2030	**REDACTED** **REDACTED** **REDACTED**
Ray Place Road - Warrenton Primary 115kV Operating Guide	6/1/2025	6/1/2027	**REDACTED** **REDACTED**
Sandersville-Wadley 115kV line Operating Guide	6/1/2025	6/1/2027	**REDACTED**
Sinai (FP&L) - South Bainbridge 115kV Operating Guide (Pre-contingency)	6/1/2027	6/1/2030	**REDACTED** **REDACTED**
South Macon 230/115kV Bank D Operating Guide (Pre-contingency)	6/1/2025	6/1/2027	**REDACTED** **REDACTED**
South Macon 230/115kV Bank F Operating Guide (Pre-contingency)	6/1/2025	6/1/2027	**REDACTED** **REDACTED**
Tallulah Lodge - Toccoa 115kV Operating Guide	6/1/2027	6/1/2029	**REDACTED** **REDACTED**
Thomaston 230/115kV Transformer Bank C Operating Guide	6/1/2025	6/1/2030	**REDACTED** **REDACTED**
Thomaston 230/115kV Transformer Bank D Operating Guide	6/1/2028	6/1/2029	**REDACTED** **REDACTED**
Thomson Primary 230/115kV Bank C Operating Guide	6/1/2025	6/1/2027	**REDACTED** **REDACTED**
Union City - Yates (White) 230kV Operating Guide	6/1/2025	6/1/2026	**REDACTED** **REDACTED** **REDACTED** **REDACTED**
West Mcintosh 500/230 kV Bank A Operating Guide	6/1/2025	6/1/2025	**REDACTED**
West Mcintosh 500/230 kV Bank B Operating Guide	6/1/2025	6/1/2025	**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-001-5 Table 1.

The following information is included for each project:

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

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

THALMANN AND COLERAIN 23O KV LINE RELAY PANEL UPGRADES

Teams # 21046

Need Date 06/01/2025 **Start Date** 12/01/2024

Description

Relay protection modifications at GPC's Thalmann and Colerain substations to match relay scheme used at GTC's new Camden Industrial Park 230/115kV 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
Estimated Cost – ITS Assigned*	REDACTED

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

ANTHONY SHOALS STATCOM SYSTEM

Teams # 20326

Need Date 12/31/2025 **Start Date** 08/04/2023

Description

Install a + 150 / - 150 MVAR turnkey STATCOM system at Anthony Shoals 230kV substation.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SAV: LITTLE OGEECHEE 230-115KV: RELAY MODERNIZATION

Teams # 17075

Need Date 12/31/2025 **Start Date** 06/01/2022

Description

Relay modernization with conversion of the 230kV ring bus to BAAH topology and addition of BAAH rung for Big Ogeechee - Little Ogeechee (Red) 230kV Line. Rebuild 115kV straight bus to BAAH design.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed in 2025

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

EAST POINT RELAY MODERNIZATION

Teams # 20491

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Upgrade protection on 230kV buses, 115kV buses, and 230/115kV auto transformer at the East Point station. Add adequate monitoring on DC supply.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GRADY 230/115KV RELAY MODERNIZATION

Teams # 20474

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Upgrade protection on 230kV bus, all 115kV buses, and both 230/115kV auto transformers at Grady. Add adequate monitoring on DC supply. Install a 230kV breaker and associated switches on the high side of Grady 230/115kV auto transformer D.

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
Estimated Cost – ITS Assigned*	REDACTED

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

KLONDIKE RELAY MODERNIZATION

Teams # 20490

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Upgrade protection on 230kV buses at the Klondike station. Add adequate monitoring on DC supply.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MORROW 115KV RELAY UPGRADE

Teams # 20300

Need Date 06/01/2026 **Start Date** 06/01/2024

Description

Upgrade protection scheme on all three 115kV buses at Morrow.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SCOTTDALE RELAY MODERNIZATION

Teams # 20489

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Upgrade protection on 230kV bus and 230/115kV auto transformers at the Scottdale station. Add adequate monitoring on DC supply.

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
Estimated Cost – ITS Assigned*	REDACTED

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

DRESDEN LINE PROTECTIVE RELAYING

Teams # 20668

Need Date 12/01/2026 **Start Date** 12/01/2024

Description

On the O'Hara - Wansley 500kV line, replace the protective relay panels associated with the 500kV line terminal facing Dresden, at both O'Hara and Wansley.

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
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: FORTSON SUBSTATION MODERNIZATION

Teams # 18832

Need Date 01/13/2027 **Start Date** 01/01/2025

Description

Complete modernization and replacement of obsolete equipment and relays for the 500kV, 230kV, and 115kV yards. Add a redundant relay scheme at Fortson.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2027

Change From Previous IRP

Project delayed from 2024 to 2027

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

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.

OHARA BREAKER REPLACEMENT

Teams # 21022

Need Date 10/01/2026 **Start Date** 10/01/2025

Description

Replace Breaker on the Ohara - Tara 115kV Line at the Ohara 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

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.

SAV: MCINTOSH - PURRYSBURG 230KV REACTORS

Teams # 20277

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Install reactors on the McIntosh - Purrysburg (Black and White) 230kV tie lines at McIntosh. Rebuild 0.1 miles (GPC portion) for both lines to (2) 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: HARTWELL DAM - HARTWELL ENERGY 230KV SERIES REACTORS

Teams # 21111

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

GTC: Replace the 1600A series reactors on the Hartwell Dam - Hartwell Energy 230kV line with 3000A.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: HARTWELL ENERGY - MIDDLE FORK 230KV LINE

Teams # 21113

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Construct a new 230kV line, approx. 35 miles, from Hartwell Energy to Middle Fork with 200C (2) 1351 ACSS conductor. GTC: Expand Hartwell Energy 230kV and Middle Fork 230kV as necessary to install breakers to accept new line termination.

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
Estimated Cost – ITS Assigned*	REDACTED

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

E. Steady State Project Details

The following projects are the result of the Steady State analyses for the TPL-001-5 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.

SAV: CC - HYUNDAI MOTORS SAVANNAH AKA. PROJECT EA

Teams # 19523

Need Date 04/25/2025 **Start Date** 06/01/2022

Description

Construct a new Hyundai 230kV substation with an eight element 230kV ring bus and four 230/25kV banks. Construct a new Newton Rd 230kV substation with a five element 230kV ring bus and loop through the Little Ogeechee - Meldrim Black and White 230kV lines. Build two new 230kV lines connecting from Hyundai - Newton Rd (12 miles) and Hyundai - Meldrim (10 miles). At Meldrim, add a breaker to accommodate for the new Hyundai line. Install a 115/25kV bank at Interstate Centre and build a new 115kV line from Interstate Centre - Hyundai (2.3 miles) for bridge power.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BANKS CROSSING - POND FORK 115 KV

Teams # 18670

Need Date 05/01/2025 **Start Date** 06/01/2021

Description

GTC will build a new 115kV line from McClure Industrial to structure 21N on the Ridgeway Church Road Junction or tap point (approximately 3 miles). Close normally open switch at Ridgeway Church Road to establish the Banks Crossing - Pond Fork 115kV line. All new conductors should be 100C 1351 ACSR Martin.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced in 2025

Change From Previous IRP

Project delayed from 2024 to 2025

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

MITCHELL - NORTH TIFTON 230KV RECONDUCTOR

Teams # 18492

Need Date 05/01/2025 **Start Date** 12/31/2021

Description

Rebuild 35.21 miles of the Mitchell - North Tifton 230kV line from 100C 795 ACSR to 100C 1351 ACSR.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced in 2025

Change From Previous IRP

Project delayed from 2024 to 2025

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

ADAMSVILLE - JACK MCDONOUGH 230KV LINE REBUILD

Teams # 19676

Need Date 06/01/2025 **Start Date** 06/01/2023

Description

Rebuild the entire 6.1 mile Adamsville - Jack McDonough 230kV line with 160C 1351 ACSS.

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
Estimated Cost – ITS Assigned*	REDACTED

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

ECHECONNEE-WELLSTON 115KV REBUILD

Teams # 18800

Need Date 06/01/2025 **Start Date** 01/01/2024

Description

Rebuild the South Warner Robins to Wellston section (1.2 miles) with 100C 1351.5 ACSR Martin conductor.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GRID - BREMEN - CROOKED CREEK (APC) 115 KV PROJECT

Teams # 19187

Need Date 06/01/2025 **Start Date** 09/01/2021

Description

Rebuild from Bremen to Indian Creek Road, on the Bremen - Crooked Creek 115kV line (14 miles), using 795 ACSR conductor at 100C.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2024 to 2025

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BONAIRE PRI-ECHECONNEE 115 KV PARTIAL REBUILD

Teams # 18153

Need Date 06/01/2025 **Start Date** 01/01/2023

Description

Rebuild 2.3 miles of the Bonaire Primary - Echeconnee 115kV line with 100C ACSR 795 conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project advanced from 2030 to 2025

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: CAMDEN INDUSTRIAL PARK 230/115KV NEW SUBSTATION

Teams # 20342

Need Date 06/01/2025 **Start Date** 01/01/2024

Description

GTC will construct a new 230/115kV substation with a three element 230kV ring bus, two element 115kV ring bus, and one new 230/115kV 400MVA transformer. A new 115kV line to Kinlaw substation will be built also.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EATONTON PRIMARY - LICK CREEK 115KV LINE SWITCH REPLACEMENT

Teams # 20590

Need Date 06/01/2025 **Start Date** 12/01/2023

Description

Replace a 1200A RLB line switch on the Eatonton - Lake Oconee 115kV line with a with motor operator and SCADA controls. This switch is located on GTC's Eatonton Primary - Lick Creek 115kV section of the Eatonton Primary - Lake Oconee 115kV Line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

JESUP - LUDOWICI PRIMARY 115KV REBUILD

Teams # 11821

Need Date 06/01/2025 **Start Date** 06/01/2023

Description

Rebuild approximately 7.5 miles of the Jesup - North Jesup - Rayonier section of the Jesup - Ludowici Primary 115kV line from 100C 336.4 ACSR Linnet conductor to 100C 795 ACSR Drake conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project delayed from 2024 to 2025

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: ALCOVY ROAD - SKC 115 KV RECONDUCTOR

Teams # 13753

Need Date 06/01/2025 **Start Date** 06/01/2023

Description

MEAG will reconductor approximately 0.53 miles of 100C 336 ACSR conductor with 100C 1033 ACSR conductor from Alcovy Road to Alcovy Road Jct. on the Alcovy Road - SKC 115kV line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: AULTMAN ROAD - BONAIRE PRIMARY 115 KV REBUILD

Teams # 13787

Need Date 06/01/2025 **Start Date** 06/01/2023

Description

MEAG: Rebuild approximately 1.99 miles of Sleepy Hollow - Peach Blossom 115kV section of the Aultman Road - Bonaire Primary 115kV line from 100C 336 ACSR to 100C 795 ACSR.
GTC: Replace the jumpers at Sleepy Hollow with 1590 AAC.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

NORCROSS 230KV BUS 1-3 SERIES BUS TIE BREAKER INSTALLATION

Teams # 20464

Need Date 06/01/2025 **Start Date** 11/01/2023

Description

Install a bus tie breaker in series with existing bus tie breaker between 230kV Bus 1 and Bus 3 at Norcross.

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
Estimated Cost – ITS Assigned*	REDACTED

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

PINE GROVE PRIMARY 115 KV DUAL STAGE CAPACITOR BANK

Teams # 19631

Need Date 06/01/2025 **Start Date** 11/01/2023

Description

Install a Dual Stage 30MVAR capacitor bank at Pine Grove Primary.

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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: DEPTFORD - MAGNOLIA 115KV RECONDUCTOR

Teams # 20067

Need Date 06/01/2025 **Start Date** 01/01/2023

Description

Reconductor the Deptford - Magnolia 115kV line (approximately 5 miles) using 973.1 C7 ACCS (Everglades) conductor and upgrade the Deptford main bus.

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
Estimated Cost – ITS Assigned*	REDACTED

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

SMART VALVE INSTALLATION

Teams # 20466

Need Date 06/01/2025 **Start Date** 10/01/2023

Description

Installation of Smart Valve devices inside the Eatonton Primary substation on the Branch - Oasis 230kV and Eatonton Primary - Oasis 230kV lines.

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
Estimated Cost – ITS Assigned*	REDACTED

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

VILLA RICA LOW SIDE BREAKER

Teams # 20431

Need Date 06/01/2025 **Start Date** 06/01/2024

Description

Replace a low side breaker at Villa Rica with a 4000A 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
Estimated Cost – ITS Assigned*	REDACTED

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

CAMDEN INDUSTRIAL PARK (GPC)

Teams # 20684

Need Date 06/30/2025 **Start Date** 01/01/2024

Description

This project will loop in GPC's existing Colerain to Thalman 230kV line into GTC's new Camden Industrial Park station. GPC's Kingsland termination at GTC's Kinlaw sub will be relocated to a new 115kV bay position.

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
Estimated Cost – ITS Assigned*	REDACTED

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

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

Teams # 18774

Need Date 12/01/2025 **Start Date** 12/01/2021

Description

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

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2024 to 2025

Change From Previous IRP

Project delayed from 2024 to 2025

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

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

Teams # 18889

Need Date 12/01/2025 **Start Date** 01/01/2024

Description

Rebuild the 115kV White line from Northwest to Jefferson Street #3 (1.2 miles) with 200C 1351 ACSS conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project advanced from 2030 to 2025

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

CC - CASS PINE- HILL VIEW 230 KV LINE- CC IMPROVEMENTS

Teams # 20152

Need Date 12/31/2025 **Start Date** 06/01/2023

Description

Build a new 7.58 mile 200C 1351 ACSS conductor 230kV line between new Cass Pine and Hill View 230kV substations.

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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - PROJECT CHRONOS- SK/HYUNDAI

Teams # 20175

Need Date 12/31/2025 **Start Date** 07/31/2023

Description

GPC will build a 230/25kV station named Two Run Ranch and loop it into the Cartersville - Pinson 230kV line to serve SK Battery/Hyundai and new load in the area.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: ANTHONY SHOALS - WASHINGTON 115 KV LINE REBUILD

Teams # 20010

Need Date 12/31/2025 **Start Date** 01/01/2024

Description

Rebuild 21 miles of the Double Branches Junction - Washington 115kV line section with 100C 795 ACSR conductor or higher rated 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: LIZARD LOPE - WESTOVER 115 KV NEW LINE

Teams # 18691

Need Date 03/01/2026 **Start Date** 06/01/2021

Description

Construct two new 115kV stations, Lizard Lope and Westover, and build a new 19.8 miles of 115kV line from Lizard Lope to Gillionville

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2026

Change From Previous IRP

Project delayed from 2024 to 2026. Previously titled "GTC: Gillionville - Greenhouse 115kV Line"

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

CC - QTS FAYETTEVILLE TRANSMISSION NEEDS

Teams # 20018

Need Date 04/01/2026 **Start Date** 06/01/2023

Description

Build a new 500/230kV substation (Ashley Park) splitting the Ohara - Union City 500kV line. Install two 500/230kV auto transformers at the Ashley Park station. At Ashley Park, the 500kV side will be a 4 - breaker ring bus, while the 230kV side will be a 2 - rung Breaker and a Half configuration. Build two new 230kV lines (~6 miles each) from Ashley Park to the high side of customer substations. The new lines will be built with bundled 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

ADAMSVILLE - BUZZARD ROOST 230KV REBUILD AND JUMPER UPGRADE

Teams # 19597

Need Date 06/01/2026 **Start Date** 06/01/2024

Description

Rebuild the line sections from Adamsville to Boat Rock Road (8.08 miles) on the Adamsville - Buzzard Roost 230kV line with 200C 1351 ACSS Martin conductor. Replace the AAC 750 jumper on the line at Adamsville with (2) 1590 AAC jumper. Replace 1590 AAC jumpers at Bakers Ferry and Boat Rock with (2) 1590 AAC jumpers. Replace 1600A line switches at Boat Rock with 3000A switches.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2027 to 2026

Change From Previous IRP

New Project

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

BLANKETS CREEK – WOODSTOCK 115KV LINE REBUILD

Teams # 18960

Need Date 06/01/2026 **Start Date** 06/01/2025

Description

Rebuild the entire Blankets Creek - Woodstock 115kV line, approximately 7.1 miles, with 200C 795 ACSS conductor.

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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - GARRETT ROAD SWITCHING STATION - TRAE LANE

Teams # 20243

Need Date 06/01/2026 **Start Date** 04/30/2023

Description

Build the new Garrett Road 230kV switching station (three - element ring bus) splitting the Villa Rica - West Marietta 230kV line. Build a new 230kV line (8.6 miles) from the Trae Lane substation to the Garrett Road switching station with bundled 100C 1351 ACSR conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2026

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

CC - STONEWALL TELL ROAD (TA REALTY)

Teams # 20216

Need Date 06/01/2026 **Start Date** 01/01/2025

Description

Build 230kV line segment, using 200C 1351 ACSS Martin conductor, to loop in the Stonewall Tell Road (TA Realty) customer station into the East Point - Union City 230kV Black line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

DU: EAST DALTON - OOSTANAULA 115KV REBUILD

Teams # 18679

Need Date 06/01/2026 **Start Date** 06/01/2023

Description

DU: Rebuild the portion of East Dalton - Oostanaula and Dalton - East Dalton 115kV double circuit lines between East Dalton substation and the Dalton substation frame with 200C 795 ACSS.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project delayed from 2023 to 2026. Project previously listed under TEAMS #18851.

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

FENWICK STREET - SAND BAR FERRY 115KV (RECONDUCTOR/REBUILD)

Teams # 16007

Need Date 06/01/2026 **Start Date** 09/01/2022

Description

Reconductor approximately 2.72 miles of transmission line from Fenwick St to East Augusta Jct. with 100C 1351 ACSR 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
Estimated Cost – ITS Assigned*	REDACTED

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

GOAT ROCK 230KV SWITCH, JUMPER, & LINE TRAP REPLACEMENT

Teams # 20516

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Replace the 230kV 1200A switch with 3000A, 90C 1351.5 ACSR Martin jumper with (2) AAC 1590, and 1600A line trap with 3000A (part of the Goat Rock - North Opelika 230kV line at Goat Rock substation.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GORDON-N DUBLIN 115KV (GORDON-ENGL MCI J) REBUILD

Teams # 19618

Need Date 06/01/2026 **Start Date** 10/01/2023

Description

Rebuild the Gordon - Engelhard McIntyre J of the Gordon - North Dublin 115kV line from 100C 336.4 ACSR (2.81 miles) Linnet and 75C 4/0 F Copper/CW (3.18 miles) to 200C ACSS 795 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GRADY - MORROW (WHITE) 115KV REBUILD

Teams # 21139

Need Date 06/01/2026 **Start Date** 06/01/2024

Description

Replace 0.72 miles of conductor from Moreland Way to Morrow including the bus and jumper at Moreland Way with 1351.5 Martin/ACSS 54/19 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
Estimated Cost – ITS Assigned*	REDACTED

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

GRID - GAINESVILLE #2 EQUIPMENT REPLACEMENT

Teams # 19706

Need Date 06/01/2026 **Start Date** 12/31/2024

Description

GPC: Replace the two 230/115kV auto transformers (Bank C and D) at Gainesville #2 with 400MVA. Project was originally maintenance driven but now compliance driven.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: CONYERS - CORNISH MOUNTAIN 115KV LINE UPGRADE

Teams # 21137

Need Date 06/01/2026 **Start Date** 06/01/2025

Description

Upgrade 750 jumpers at North Conyers and raise the temperature rating of the 636 ACSR conductor on the Conyers - Cornish MTN 115kV line from 100C to 125C.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: LAGRANGE - NORTH OPELIKA 230 KV

Teams # 19334

Need Date 06/01/2026 **Start Date** 06/01/2023

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 - mile section from Lagrange to the Metering Station near the Georgia - Alabama border. The Metering Station will be owned by GTC. GPC will construct the short line section from the Metering Station to the GA - AL state line. APC will construct the 230kV line from the GA - AL state line to North Opelika.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project advanced from 2027

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: MORNING HORNET 2ND 230/115 KV BANK & THUMBS UP 115KV TL

Teams # 20015

Need Date 06/01/2026 **Start Date** 06/01/2024

Description

GTC to add a second 230/115kV auto transformer at Morning Hornet substation. Also, build an additional 115kV line from Morning Hornet to Thumbs Up, approximately 2.4 miles, using at least 100C 1351 ACSR 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: ROBINS SPRING BUS REPLACEMENT

Teams # 19999

Need Date 06/01/2026 **Start Date** 06/01/2023

Description

GTC: Replace the main 115kV bus 90C ACSR 336.4 Linnet conductor with higher rating.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2026

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: ROBINS SPRING CAPACITOR BANK INSTALLATION

Teams # 20001

Need Date 06/01/2026 **Start Date** 01/01/2023

Description

Install a 115kV 2 - stage 22.5MVAR (45MVAR total) capacitor bank at Robins Spring

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2026

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

HAMMOND - WEISS DAM 115KV LINE REBUILD

Teams # 19636

Need Date 06/01/2026 **Start Date** 06/01/2023

Description

Rebuild 11.2 miles of Hammond - Weiss Dam 115kV from Hammond to the APC border with 200C 795 ACSS.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

KATHLEEN AREA IMPROVEMENTS

Teams # 20512

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Rebuild the Kathleen - Big Grocery Creek 230kV line (approximately 1.5 miles).
Rebuild the Bonaire Primary - Kathleen 230kV line (approximately 6 miles).
Upgrade limiting elements at Kathleen substation.

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
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: DRESDEN - LAGRANGE PRIMARY 230KV UPGRADE & JUMPERS

Teams # 19598

Need Date 06/01/2026 **Start Date** 06/01/2024

Description

MEAG will re-sag the Dresden - LaGrange Primary 230kV line to 125C. Replace the jumpers at Dresden and LaGrange with (2) 1590 AAC jumpers.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: RAY PLACE RD - WASHINGTON #3

Teams # 20270

Need Date 06/01/2026 **Start Date** 01/01/2024

Description

Rebuild the Ray Place Rd - Washington 115kV line with 100C 795 ACSR conductor (total 17.4 Miles) between Ray Place Rd and Washington 2. Replace Jumpers and bus at Washington 2.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: RAY PLACE RD - WASHINGTON (WASHINGTON - WASHINGTON 3)

Teams # 20271

Need Date 06/01/2026 **Start Date** 06/01/2025

Description

MEAG will rebuild the Ray Place Rd - Washington 115kV line with 100C 1351 ACSR conductor (total 1.2 Miles) between Washington and Washington 3. Replace jumpers at Washington.

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
Estimated Cost – ITS Assigned*	REDACTED

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

PALMYRA REACTOR REMOVAL

Teams # 18690

Need Date 06/01/2026 **Start Date** 05/01/2023

Description

Remove the 6% reactor at the Palmyra Substation.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2026

Change From Previous IRP

Project delayed from 2024 to 2026

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: BOULEVARD - DEPTFORD 115KV RECONDUCTOR

Teams # 20066

Need Date 06/01/2026 **Start Date** 06/01/2025

Description

Reconductor the Boulevard - Deptford 115kV line (approximately 8 miles) using 973.1 C7 ACCS (Everglades) conductor. Upgrade main bus and jumpers at Bolton substation from 90C 1590 AAC Coreopsis to 90C (2)1590 AAC Coreopsis or higher rated equipment.

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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: CC - BIG OGEECHEE 500/230KV (CC NETWORK IMPROVEMENTS)

Teams # 19966

Need Date 06/01/2026 **Start Date** 06/01/2023

Description

Construct a new substation near Little Ogeechee, adjacent to the 500kV and 230kV shared right of way for McCall Road - Thalmann 500kV and the Little Ogeechee - Meldrim 230kV Black and White lines. The new substation will loop in the existing McCall Road - Thalmann 500kV line, the existing Little Ogeechee - Meldrim 230kV lines, and accommodate a new 1344MVA 500/230kV auto transformers with an additional 230kV connection to Little Ogeechee.

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
Estimated Cost – ITS Assigned*	REDACTED

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

UNION CITY - YATES 230 KV WHITE LINE REBUILD

Teams # 17900

Need Date 06/01/2026 **Start Date** 06/01/2023

Description

Rebuild 23.4 miles of the Union City - Yates 230kV White line with bundled 1351 ACSS Martin conductor at 200C.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Delayed in 2026.

Change From Previous IRP

New Project

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

UNION CITY - YATES 230KV (WHITE) SWITCH AND TRAP REPLACEMENT

Teams # 20691

Need Date 06/01/2026 **Start Date** 05/15/2024

Description

Replace the limiting elements at Union City and Yates substations along the Union City - Yates 230kV (White) line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - PROJECT PAYTON BAINBRIDGE

Teams # 20223

Need Date 06/30/2026 **Start Date** 06/01/2024

Description

Split Farley - South Bainbridge 230kV line with a 230kV station (Dothan Road) and bring an 8.5 mile 200C 1351 ACSS 230kV line from Dothan Rd to new customer sub Downrange. Bring another 10mile 200C 1351 ACSS 230kV line from Climax to customer sub Downrange.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BARNESVILLE PRIMARY-BARNESVILLE #1 115KV RECONDUCTOR

Teams # 20874

Need Date 12/01/2026 **Start Date** 06/01/2024

Description

Rebuild approximately 4.53 miles of the Barnesville Primary - Barnesville #1 segment on the Barnesville Primary - Lamar County Industrial 115kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: DRESDEN 500KV BUS EXPANSION

Teams # 20273

Need Date 12/01/2026 **Start Date** 12/01/2024

Description

GTC will expand the Dresden 500kV bus into a 5 - element ring bus configuration. Loop the O'Hara - Wansley 500kV line into the Dresden 500kV substation and allow for future Dresden - Talbot 500kV line termination.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: GORDON - SANDERSVILLE #1 115KV LINE REBUILD

Teams # 20002

Need Date 12/01/2026 **Start Date** 02/01/2023

Description

Rebuild the 1.87 miles of Sandersville #1 - Sandersville #6 line section of the Gordon - Sandersville #1 115kV line from 100C ACSR 336 conductor to 100C ACSR 795 conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed in 2026

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

CC - CASS PINE 230/25 NEW SUB - QCELLS - CC IMPROVEMENTS

Teams # 20151

Need Date 12/31/2026 **Start Date** 06/01/2024

Description

Build a new 230/25kV 8 element ring bus networked substation named Cass Pine that will interconnect between new Great Valley and Hill View 230kV substations.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GRADY-WEST END 115KV REBUILD

Teams # 19287

Need Date 12/31/2026 **Start Date** 06/01/2022

Description

Reconductor the Grady - West End 115kV line (2.6 miles) using 200C 1351 ACSS Martin.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project delayed from 2024 to 2026

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MORROW - MOUNTAIN VIEW 115 KV REBUILD

Teams # 19363

Need Date 12/31/2026 **Start Date** 01/01/2024

Description

Rebuild the Mountain View - Barnett Road section of the Morrow - Mountain View 115kV line with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - EMBLEM RIVERSIDE CUSTOMER SUB (FLEXENTIAL)

Teams # 20509

Need Date 03/01/2027 **Start Date** 06/01/2025

Description

A new customer substation, Emblem Riverside, is being built along the Buzzard Roost - Douglasville 230kV line. Moreover, a Fiber ICON ring is being built in the area to help with communications and protection for all customers in the area.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: HICKORY LEVEL - VILLA RICA 230KV LINE RECONDUCTOR

Teams # 19635

Need Date 05/01/2027 **Start Date** 05/01/2024

Description

GTC will reconductor from 100C 1351 ACSR to 160C 1351 ACSS on 8.6 miles of 230kV line. A 2000A line trap at Villa Rica will also be replaced with a 3000A line trap.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2029 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

MORROW - YATES COMMON 115KV LINE UPGRADE

Teams # 19601

Need Date 05/01/2027 **Start Date** 05/01/2024

Description

On the Fife - Fairburn SW - Owens Corning Tap sections of the Morrow - Yates Common 115kV line, rebuild approximately 5.8 miles of 50C 477 ACSR with 210C 1334 T13 ACCR Martin or 200C 1351.0 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

POSSUM BRANCH - YATES COMMON 115KV REBUILD (YATES TO CLEM)

Teams # 15879

Need Date 05/01/2027 **Start Date** 06/01/2025

Description

Rebuild 11.2 miles of 100C 477 ACSR with 200C 1334 T13 ACCR Martin or 200C 1351.0 ACSS between Yates Common to Oak Mountain. Replace limiting elements along the line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

CC - GULLATT ROAD TRANSMISSION IMPROVEMENTS

Teams # 20771

Need Date 06/01/2027 **Start Date** 06/01/2024

Description

Upstream Transmission improvements to serve a new customer station being built along the Morrow - Yates Common 115kV and Line Creek - Fairburn #2 115kV lines. Rebuild the Morrow - Yates Common 115kV line from Line Creek to the new Gullatt Road customer station. Rebuild the Line Creek - Fairburn #2 115kV line from Line Creek to the new Gullatt Road customer station. Remove the Owens Corning Tap Connection on the Morrow - Yates Common 115kV line and rebuild the line from North Coweta to Str 1. Build new line section from Str 1 to the new Gullatt Road customer station

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

CC - MICROSOFT - SHUGART (CCO06)

Teams # 18736

Need Date 06/01/2027 **Start Date** 12/31/2022

Description

GPC will rebuild the Line Creek 230kV substation as breaker and a half configuration and connect the Morrow - Yates 230kV line and the Union City - Yates 230kV White line into Line Creek. For the Union City - Yates 230kV Black line, terminate the line from the Yates side into Shugart Farms, and the line from the Union City side into Line Creek. Build two short lines from Line Creek to Shugart Farms (0.3 miles each) with 100C 1351 ACSR Martin conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2024 to 2027

Change From Previous IRP

New project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

CC - SUMMER LAKE - VILLA RICA 230KV REBUILD (CC IMPROVEMENT)

Teams # 20781

Need Date 06/01/2027 **Start Date** 06/01/2025

Description

Rebuild the 2.5 mile section from Villa Rica to the new East Villa Rica Switching station on the Summer Lake - Villa Rica 230kV line with bundled 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - TA REALTY ELLENWOOD NETWORK IMPROVEMENTS

Teams # 20736

Need Date 06/01/2027 **Start Date** 06/01/2024

Description

Rebuild the ~14.9mi Austin Drive - Morrow 115kV with 200C 1351.5 ACSS Martin. At Austin Drive 115kV, replace the 115/230kV auto transformer along with upgrades other limiting elements at the station.

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
Estimated Cost – ITS Assigned*	REDACTED

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

DOYLE - LG&E MONROE 230KV - JACKS CREEK LOOP IN

Teams # 20234

Need Date 06/01/2027 **Start Date** 01/03/2027

Description

Loop in and out the new Jack's Creek 230kV switching station into the Doyle - LG&E Monroe 230kV line. This is coordinated with the East Walton Project (TEAMS #09662).

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: ADAMSVILLE - BUZZARD ROOST 230KV REBUILD

Teams # 20858

Need Date 06/01/2027 **Start Date** 06/01/2025

Description

GTC plans to rebuild 5 miles of line from Buzzard Roost to Boat Rock Road with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: DOUGLASVILLE - VILLA RICA 230KV REBUILD (CC IMPROVEMENT)

Teams # 20776

Need Date 06/01/2027 **Start Date** 06/01/2025

Description

Rebuild the 2.5 mile section from Villa to the new East Villa Rica Switching station on the Douglasville - Villa Rica 230kV line with bundled 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: DOYLE - WINDER PRIMARY 230KV LINE JUMPER REPLACEMENT

Teams # 20778

Need Date 06/01/2027 **Start Date** 12/31/2025

Description

Replace the limiting AAC 1033 jumper with AAC 1590 at Doyle on the Doyle - Winder Primary 230kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EAST MOULTRIE - HIGHWAY 112 230 KV LINE

Teams # 19358

Need Date 06/01/2027 **Start Date** 06/01/2022

Description

Build a new 27 miles of 230kV line between HWY 112 and East Moultrie substations with 100C 1351 ACSR 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EAST WALTON 500/230KV PROJECT

Teams # 09662

Need Date 06/01/2027 **Start Date** 06/01/2023

Description

GTC:
- Construct the East Walton 500/230kV substation.
- Construct the Bostwick 230kV switching station.
- Construct the East Walton - Rockville 500kV line (3 - 100C 1113 ACSR).
- Construct the Bethabara - East Walton 230kV line (170C 1351.5 ACSS).
- Construct the Bostwick - East Walton 230kV line (170C 1351.5 ACSS).
- Construct the East Walton - Jack's Creek 230kV line (170C 1351.5 ACSS).
- At Bethabara, terminate the East Walton 230kV line.
- Loop the East Social Circle - East Watkinsville 230kV line into Bostwick.
- Replace line trap at East Watkinsville on the Bostwick 230kV line.

GPC:
- Construct the Rockville 500kV switching station.
- Loop the Scherer - Warthen 500kV line into Rockville.
- Loop the Doyle - LG&E Monroe 230kV line into Jack's Creek.

MEAG:
- Construct the Jack's Creek 230kV switching station.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: GARRETT RD - V. RICA 230KV LINE RECONDUCTOR (CC NET IM)

Teams # 20505

Need Date 06/01/2027 **Start Date** 01/01/2027

Description

GTC will reconductor the section from East Villa Rica Switching station to Garrett Rd with 160C 1351 ACSS on 11.5 miles of the Garrett Road - Villa Rica 230kV line. Additionally, the 2.5 miles section from East Villa Rica Switching Station to Villa Rica will be rebuilt with bundled 200C 1351 ACSS Martin.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2029 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: RIDDLEVILLE BUS REPLACEMENT

Teams # 19622

Need Date 06/01/2027 **Start Date** 01/09/2023

Description

GTC will replace the main 115kV bus at Riddleville substation with higher rating.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2024 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: SKC 115KV BUS AND JUMPER REPLACEMENT

Teams # 19606

Need Date 06/01/2027 **Start Date** 06/01/2025

Description

Replace the 115kV bus and jumpers at SKC substation with higher rated bus and jumpers with rating higher than 255MVA.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: SOUTH HAZLEHURST - NEW LACY 230KV LINE

Teams # 20020

Need Date 06/01/2027 **Start Date** 01/15/2024

Description

GTC will build a new 230kV transmission line between South Hazlehurst (bus 2) and New Lacy substation (approximately 25 miles) with 100C ACSR 1351 Martin conductor. Do all the necessary upgrade work to accommodate the additional line in both facilities.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: SWITCH WAY - THORNTON ROAD 230KV LINE REBUILD

Teams # 20506

Need Date 06/01/2027 **Start Date** 01/01/2025

Description

GTC will rebuild the 1.3 mile Switchway - Thornton Rd 230kV line with 200C 1351 ACSS.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

JESUP - OFFERMAN 115KV REBUILD

Teams # 18668

Need Date 06/01/2027 **Start Date** 04/06/2021

Description

Rebuild 20 miles of 100C 4/0 ACSR Penguin conductor along the Jesup - Offerman 115kV line, with 100C 795 ACSR Drake conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Change

Change From Previous IRP

Project delayed from 2024 to 2027

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

LAWRENCEVILLE - WINDER 115KV LINE REBUILD

Teams # 10143

Need Date 06/01/2027 **Start Date** 10/15/2026

Description

Rebuild approximately 1.2 miles of 100C 636 ACSR conductor from Johns Manville to Winder Primary with 200C 795 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

LAWRENCEVILLE - WINDER PRIMARY 230KV LINE REBUILD

Teams # 10481

Need Date 06/01/2027 **Start Date** 06/01/2024

Description

Rebuild the entire Lawrenceville - Winder Primary 230kV line, approximately 15.4 miles, using 200C 1351 ACSS "Martin" conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2029 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: RAY PLACE RD - WARRENTON PRIMARY

Teams # 20264

Need Date 06/01/2027 **Start Date** 01/01/2026

Description

Rebuild 10 miles of Ray Place - Warrenton Primary 115kV line with 100C 2 - 1351 ACSR conductor and replace 1590 AAC Coreopsis jumpers at Warrenton.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2030 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SANDERSVILLE #1 - WADLEY PRI. 115KV REBUILD/RECONDUCTOR

Teams # 19248

Need Date 06/01/2027 **Start Date** 02/15/2022

Description

Rebuild approximately 24.3 miles of the Sandersville #1 - Wadley Primary 115kV line from 100C 336 ACSR Linnet conductor to 100C 1351 ACSR Drake conductor. Replace limiting elements in substations along the line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SAV: GOSHEN (SAV) - KRAFT 115KV LINE REBUILD

Teams # 20785

Need Date 06/01/2027 **Start Date** 06/01/2024

Description

Rebuild 9.3 miles of Goshen - Kraft 115kV line from Kraft - Godley J - Rice Hope from 100C 795 ACSR Drake to 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: GOSHEN (SAV) - MCINTOSH 115KV LINE REBUILD

Teams # 20065

Need Date 06/01/2027 **Start Date** 06/01/2025

Description

Rebuild the Goshen (Savannah) - Georgia Pacific (Rincon) section, approximately 6.7 miles, of the Goshen (Sav) - McIntosh 115kV line using 100C 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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - TOMOCHICHI 500/230KV SOLUTION (CC NETWORK IMPROVEMENTS)

Teams # 20717

Need Date 07/15/2027 **Start Date** 06/01/2024

Description

Build the new Tomochichi 500/230kV switching station (four element ring bus 500kV high side, four element breaker and a half 230kV low side) splitting the Ohara - Schere 500kV line. Build two new 230kV lines from the new Tomochichi substation to the new Towaliga River 230kV 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GRID - ARKWRIGHT - LLOYD SHOALS 115KV

Teams # 18573

Need Date 07/30/2027 **Start Date** 06/01/2021

Description

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

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2024 to 2027

Change From Previous IRP

Project delayed from 2024 to 2027. Previously listed under TEAMS #12016.

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EATONTON PRIMARY (035591) - LICK CREEK 115KV REBUILD

Teams # 20591

Need Date 12/01/2027 **Start Date** 10/01/2023

Description

Rebuild approximately 7.5 miles Eatonton Primary - Lick Creek 115kV line section with 100C 795 ACSR 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

ATHENA - EAST WATKINSVILLE 115 KV (REBUILD)

Teams # 17977

Need Date 12/31/2027 **Start Date** 08/01/2024

Description

Rebuild 8.47 miles of the University of Georgia - East Watkinsville line sections on the Athena - East Watkinsville 115kV line with 100C ACSR 1033 conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Delayed from 2026 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

CC - HILL VIEW & GRASSY HOLLOW SUB - CC IMPROVEMENTS

Teams # 20150

Need Date 12/31/2027 **Start Date** 06/01/2023

Description

Build two 230kV switching stations (Hill View and Grassy Hollow) looping into the Cartersville - McGrau Ford 230kV line (8.5 miles apart). Build two new 230kV lines: Cass Pine - Great Valley and Great Valley - Grassy Hollow (total 10.1 miles) with 200C 1351 ACSS Martin.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2024 to 2027

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

DYER ROAD - EAST ROANOKE 115KV (REBUILD)

Teams # 20024

Need Date 12/31/2027 **Start Date** 06/01/2025

Description

Rebuild 20.7 miles of 75C 397.5 ACSR conductor with advanced conductor from Dyer Road to Wansley tap on the Dyer Road - East Roanoke (APC) 115kV line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

AULTMAN ROAD-PERRY 115KV LINE REBUILD

Teams # 19997

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild the PPG J2 - Langston Road line section of the Aultman Road - Perry 115kV line from 100C 336 ACSR Linnet conductor to 200C 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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - EAST VILLA RICA AREA SWITCHING STATION (CC IMPROVEMENT)

Teams # 20797

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Build a 7 rung breaker and a half switching station along the right of way of the (3) 230kV lines about 2.5 miles East of Villa Rica to service recently signed customers in the area. All three lines will terminate into this station.

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
Estimated Cost – ITS Assigned*	REDACTED

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

CC - VILLA RICA UPGRADES (CC NETWORK IMPROVEMENTS)

Teams # 20774

Need Date 06/01/2028 **Start Date** 06/01/2026

Description

Loop in the Bowen - Union City line into Villa Rica 500kV bus and add a second 2016 MVA 500/230kV auto transformer. Convert the 230kV side to a 10 element breaker and a half scheme.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

FITZGERALD - PITTS 115 KV LINE REBUILD

Teams # 21048

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild approximately 26.14 miles of the Fitzgerald - Pitts 115kV line with 200C 1351 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BARNESVILLE - SOUTH GRIFFIN 230KV PROJECT

Teams # 08458

Need Date 06/01/2028 **Start Date** 01/01/2026

Description

Construct 19 miles of 230kV circuit, on existing ROW, using200C 1351 ACSS conductor from South Griffin 230/115kV substation to the Barnesville 230/69kV 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BARNEYVILLE - EAST MOULTRIE 115KV NEW LINE

Teams # 20503

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Build a new 20 miles of 115kV line with 200C 1351 ACSS from Barneyville to East Moultrie. Add 115kV breakers to Barneyville and East Moultrie substations.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BONAIRE PRIMARY 500/230KV XFMR REPLCMNT & RELAY MOD

Teams # 20873

Need Date 06/01/2028 **Start Date** 03/14/2024

Description

Replace 500/230kV, auto transformer C with a new 448 MVA transformer. Replace obsolete relay panels.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BOSTWICK - EAST SOCIAL CIRCLE 230KV RECONDUCTOR

Teams # 19992

Need Date 06/01/2028 **Start Date** 12/31/2024

Description

Reconductor 10.8 miles of the East Social Circle - East Watkinsville 230kV line (up to future Bostwick location) from 1033 ACSR Curlew conductor to 1033 ACCR 200C conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2030 to 2028

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

JACK MCDONOUGH - NORTHWEST (BLACK) 230KV RECONDUCTOR

Teams # 20777

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild the Jack McDonough - Northwest (Black) 230kV line (4.59 miles) using 200C 1351 Elbrus/TW.

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
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: BRUMBLEY CREEK - SOUTH BAINBRIDGE 115KV REBUILD

Teams # 19629

Need Date 06/01/2028 **Start Date** 01/01/2024

Description

Rebuild 2.1 miles segment from line tap into Roddenbery Station on the South Bainbridge - Thomasville 115kV line from 50C ACSR TW 762.8 to 200C 1351 ACSS conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2025 to 2028

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: THOMASVILLE 230/115KV AUTOBANK REPLACEMENT

Teams # 19630

Need Date 06/01/2028 **Start Date** 06/01/2027

Description

Replace the 140MVA 230/115kV auto transformer #4 at Thomasville substation.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2029 to 2028

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

PITTMAN ROAD - WEST POINT DAM (USA) 115KV REBUILD

Teams # 20482

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild 3 miles from the Pittman Road 115kV station to the West Point Dam (USA) 115kV station with 100C 1351 ACSS Martin conductor. Replace AAC 750 jumper at Pittman Road 115kV with (2) 1590 AAC.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2031 to 2028

Change From Previous IRP

New Project

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

PLANT YATES BREAKER AND HALF STATION

Teams # 20656

Need Date 06/01/2028 **Start Date** 05/01/2024

Description

Rebuild the Yates 6 & 7 substation to a Breaker and a Half configuration.

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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: COLEMAN - DEAN FOREST 115KV LINE REBUILD

Teams # 20783

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild entire line from Coleman to Dean Forest. 6.67 miles of 100C 477 Hawk Conductor with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: MAGNOLIA - TRUMAN PARKWAY 115KV REBUILD

Teams # 20407

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild 3 miles of the Magnolia - Truman Parkway 115kV from 75C 927 ACAR to 200C 1351 ACSS Martin conductor or higher rated conductor. Upgrade 1200A switches at Magnolia substation to 2000A switches and jumpers at Truman Parkway.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

No Changes

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

SMART VALVES AT EAST VILLA RICA SWITCHING STATION

Teams # 21069

Need Date 06/01/2028 **Start Date** 06/01/2028

Description

Installation of Power Flow Controllers at the new East Villa Rica Switching Station on the Douglasville - Villa Rica 230kV and Summer Lake - Villa Rica 230kV lines. The Power Flow Controllers will be removed when GTCs strategic project at Cavender Drive goes in service.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SOUTH MACON 115KV BUSES 1 & 2 REPLACEMENT

Teams # 20768

Need Date 06/01/2028 **Start Date** 01/15/2025

Description

Replace the 115kV buses 1 and 2 at South Macon 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

UNION CITY - YATES 230KV (BLACK) LINE REBUILD

Teams # 20274

Need Date 06/01/2028 **Start Date** 06/01/2025

Description

Rebuild the Union City - Yates 230kV Black line with bundled 200C 1351 ACSS Martin conductor. Replace limiting elements at Union City, Fairburn #1 and Line Creek substations.

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
Estimated Cost – ITS Assigned*	REDACTED

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

FIRST AVENUE - NORTH COLUMBUS 115KV LINE REBUILD

Teams # 13166

Need Date 12/01/2028 **Start Date** 01/01/2028

Description

Rebuild the 0.9 miles North Columbus - First Avenue 115kV line (currently 75C 657 ACAR) with 200C 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: NORTH DUBLIN 230/115KV TRANSFORMERS AND BUS-TIE BREAKER

Teams # 20586

Need Date 12/01/2028 **Start Date** 11/01/2023

Description

Replace 230/115kV auto transformers A & B with (2) new 230/115kV, 400 MVA auto transformers. Replace 230kV bus tie breaker with a new 2000A breaker. Replace 115kV bus tie breaker with a new 2000A breaker.

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
Estimated Cost – ITS Assigned*	REDACTED

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

ASHLEY PARK-WANSLEY 500KV

Teams # 21062

Need Date 06/01/2029 **Start Date** 12/01/2024

Description

Construct a 500kV line from Ashley Park to Wansley, approximately 35 miles long.

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
Estimated Cost – ITS Assigned*	REDACTED

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

BLAKELY PRIMARY - HUCKLEBERRY 115KV REBUILD

Teams # 10222

Need Date 06/01/2029 **Start Date** 06/01/2025

Description

Rebuild the Blakley Primary - Huckleberry 115kV line from 75C 477 ACSR to 200C 1351 ACSS. (13.5 miles)
GPC: Replace jumpers at Blakely Primary
GTC: Replace jumpers at Blakely and Huckleberry

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

BROADWAY - ECHECONNEE 115 KV LINE REBUILD

Teams # 21047

Need Date 06/01/2029 **Start Date** 01/01/2025

Description

Rebuild the Griffin Rd – Echeconnee line section of Broadway - Echeconnee line with 200C 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
Estimated Cost – ITS Assigned*	REDACTED

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

BUTLER - THOMASTON 230KV LINE CONVERSION

Teams # 16887

Need Date 06/01/2029 **Start Date** 01/01/2025

Description

Rebuild the radial Thomaston - Butler 115kV line to 230kV network operation.
Make all necessary upgrades and accommodations at Butler and Thomaston. Convert the Wesley substation from 115kV to 230kV.

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
Estimated Cost – ITS Assigned*	REDACTED

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

BUZZARD ROOST - FACTORY SHOALS 230KV NEW LINE

Teams # 21036

Need Date 06/01/2029 **Start Date** 06/01/2026

Description

A new 2 mile 230kV line is being built from Buzzard Roost to Factory Shoals with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

CONYERS - KLONDIKE 230 KV SECOND LINE

Teams # 21142

Need Date 06/01/2029 **Start Date** 06/01/2026

Description

Build a new 6.56 mile line from Conyers to Klondike with 200C (2) 1351 ACSS Martin conductor. Build one new 230kV breaker terminal at Conyers and one new 230kV terminal at Klondike.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GLENWOOD SPRINGS - PORTERDALE PRIMARY 230KV LINE SWITCH REPL

Teams # 21138

Need Date 06/01/2029 **Start Date** 06/01/2029

Description

Replace the 600A line switch at Porterdale Primary on the Glenwood Springs - Porterdale Primary 230kV Line with 1200A 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: BARNESVILLE PRIMARY - THOMASTON 230KV

Teams # 21112

Need Date 06/01/2029 **Start Date** 06/01/2027

Description

Rebuild Barnesville Primary - Thomaston 230kV line (13.24 miles) with 100C 1351 ACSS; Replace 1200A switches at Barnesville Primary & Thomaston with 3000A switch; replace associated jumper at both stations.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BAY CREEK 230/115KV SECOND AUTO TRANSFORMER

Teams # 10814

Need Date 06/01/2029 **Start Date** 06/01/2028

Description

Install a second 230/115kV, 400 MVA auto transformer at the Bay Creek substation.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BONAIRE PRIMARY - EASTMAN PRIMARY 115 KV LINE REBUILD

Teams # 21140

Need Date 06/01/2029 **Start Date** 01/01/2026

Description

Rebuild 41.08 miles of the Bonaire Primary - Eastman Primary 115kV Line using 200C 1351ACSS Martin and upgrade the bus at Roddy 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: CLIFTONDALE - LINE CREEK 230KV LINE

Teams # 20849

Need Date 06/01/2029 **Start Date** 06/01/2026

Description

An 11.6 mile 230kV line is being built form Cliftondale to Line Creek with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: DRESDEN - TALBOT 500KV LINE

Teams # 19950

Need Date 06/01/2029 **Start Date** 06/01/2025

Description

GTC will build a new 500kV line from Talbot to Dresden (75 miles). This project will create a new Talbot 500/230kV substation with a 500/230kV auto transformers. The low side of the auto transformers will connect to the Talbot County #1 and #2 230kV buses.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: HOPEWELL 230/115 KV BANK A

Teams # 20760

Need Date 06/01/2029 **Start Date** 06/01/2028

Description

Replace the Hopewell 230/115kV auto transformer with a 400 MVA auto transformer.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: TENASKA - WANSLEY 500KV NEW LINE

Teams # 21123

Need Date 06/01/2029 **Start Date** 12/01/2024

Description

Construct a 5 mile long 500kV line between Tenaska and Wansley. Make all necessary accommodations at the substations for the line termination.

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
Estimated Cost – ITS Assigned*	REDACTED

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

LLOYD SHOALS - PORTERDALE PRIMARY 115KV REBUILD

Teams # 21141

Need Date 06/01/2029 **Start Date** 03/01/2026

Description

Rebuild 15.8 miles of 50C 397.5 ACSR Ibis with 200C 1351 ACSS Martin from Jackson Lake to Lloyd Shoals and Jackson Lake to South. Covington Junction.

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
Estimated Cost – ITS Assigned*	REDACTED

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

LOWER RIVER - WEBB (APC) 115KV RECONDUCTOR

Teams # 20285

Need Date 06/01/2029 **Start Date** 06/01/2025

Description

Reconductor 0.97 miles of 100C 636 Grosbeak Lower River - Webb 115kV line with 200C 795 ACSS Drake conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2030 to 2029

Change From Previous IRP

New Project

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MCEVER ROAD - SHOAL CREEK 115KV REBUILD

Teams # 19621

Need Date 06/01/2029 **Start Date** 12/31/2024

Description

Rebuild the 636 ACSR (1 mile) of the McEver Road - College Square section, and 2 - 4/0 copper part (2.05 miles) of the College Square to Lakeside WTP B line section, part of the McEver Road - Shoal Creek 115kV line, using 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

MCMANUS - WEST BRUNSWICK 115KV REBUILD

Teams # 20346

Need Date 06/01/2029 **Start Date** 01/01/2026

Description

Rebuild the McManus - West Brunswick 115kV line, approximately 5.7 miles, with 200C 1351 ACSS 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV REBUILD

Teams # 17706

Need Date 06/01/2029 **Start Date** 06/01/2026

Description

Rebuild approximately 8 miles of the Aultman Road - Fort Valley #1 115kV line with 200C 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: SLAPPEY DRIVE - WESTOVER 115KV LINE REBUILD

Teams # 11051

Need Date 06/01/2029 **Start Date** 06/01/2026

Description

Rebuild 2.92 miles of 100C sagged 477 ACSR Hawk conductor from Slappey Drive to Albany #9 with 1351 ACSR.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

NORCROSS - NORTH DRUID HILLS 115KV REBUILD

Teams # 20757

Need Date 06/01/2029 **Start Date** 01/01/2025

Description

Rebuild the Norcross - Norcross Junction (674) segment, approximately 3.9 miles, from 100C 477 ACSR Hawk conductor to 200C 1351 ACSS "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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: BOULEVARD - MAGNOLIA 115 KV LINE REBUILD

Teams # 21006

Need Date 06/01/2029 **Start Date** 01/01/2027

Description

Rebuild the entire line from Boulevard to Magnolia (4.56 miles) from 100C 795 ACSR Drake to 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: DEAN FOREST - LITTLE OGEECHEE 230 KV REBUILD

Teams # 21023

Need Date 06/01/2029 **Start Date** 01/01/2026

Description

Rebuild the entire line from Little Ogeechee - Salt Creek and Salt Creek - Dean Forest, approximately 8 miles, using 200C 1351 ACSS/Martin. Upgrade jumpers at the Little Ogeechee terminal.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SAV: RICE HOPE NEW AUTO TRANSFORMER

Teams # 20989

Need Date 06/01/2029 **Start Date** 06/01/2025

Description

Install a new 230/115kV 400MVA auto transformer at Rice Hope and loop in the Crossgate - McIntosh 230kV line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

SOUTH BAINBRIDGE - SINAI (FPL) 115KV LINE RECONDUCTOR

Teams # 13628

Need Date 06/01/2029 **Start Date** 06/01/2025

Description

Rebuild the Four Mile tap - Recovery - Sinai (FPL) segment of the Sinai (FPL) - South Bainbridge 115kV line from 100C 336.4 ACSR to 200C 1351 ACSS. 9.8 miles in FPL and 13.75 miles in GPC
At Recovery (GTC): Replace 100C 336.4 ACSR string bus with higher rating and jumpers with (1) 1590 AAC
At Sinai (FPL): Replace 100C 336.4 ACSR string bus with higher rating

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
Estimated Cost – ITS Assigned*	REDACTED

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

BAY CREEK - CONYERS 230KV REBUILD

Teams # 20248

Need Date 12/31/2029 **Start Date** 06/01/2031

Description

GPC will rebuild the Bay Creek - Conyers 230kV line, approximately 15.29 miles, using 200C 1351 ACSS "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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

ANNISTON - HAMMOND 230KV LINE

Teams # 21129

Need Date 06/01/2030 **Start Date** 06/01/2025

Description

Rebuild the 28.12 miles section between Hammond and the Goshen tap with 200C 1351 ACSS 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

ATKINSON - NORTHSIDE DRIVE 115KV REBUILD

Teams # 20764

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Rebuild a portion of the Atkinson - Northside 115kV line, approximately 3.2 miles from Atkinson to Chattahoochee with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

ATKINSON - NORTHWEST 115KV REBUILD

Teams # 20761

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Rebuild the 1.2 mile Atkinson - Tilford Yards section of the Atkinson - Northwest 115kV with 200C 1351 ACSS 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

CC - NORTH GEORGIA DATA NETWORK UPGRADES

Teams # 21130

Need Date 06/01/2030 **Start Date** 06/01/2026

Description

Construct approximately 7 miles of 115kV line with minimum 170C 1351 ACSS conductor from Gillsville Tap Junction to Midway. Utilize the existing GPC owned North Jackson - Lawrence Smith 46kV ROW that is to be retired. Disconnect the East Maysville 115kV tap at Midway 115kV and terminate the new Pond Fork - Midway 115kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

CORNELIA - TALLULAH LODGE 115KV REBUILD

Teams # 10478

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Rebuild approximately 9.7 miles of the Cornelia - Chase Road - Clarksville - Hollywood segments of the Cornelia - Tallulah Lodge 115kV line with 200C 795 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
Estimated Cost – ITS Assigned*	REDACTED

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

DU: DAWSON CROSSING - NELSON (WHITE) 115 KV REBUILD

Teams # 18669

Need Date 06/01/2030 **Start Date** 12/31/2024

Description

Rebuild approximately 15.7 miles of the Dawson Crossing - Etowah - Reavis Mountain - Nelson sections of the Dawson Crossing - Nelson (White) 115kV line with 1351 ACSS conductor. GPC will make any necessary relaying changes at Dawson Crossing.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

New Project

Change From Previous IRP

Project delayed from 2028 to 2030

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

EAST POINT - TRIBUTARY 230KV REBUILD

Teams # 21097

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Rebuild the 2.9 mile section from Cavender Drive to Marietta 25 with 200C 1351 ACSS conductor on the East Point - Tributary 230kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

EAST POINT - UNION CITY 230KV BLACK LINE RECONDUCTOR

Teams # 20480

Need Date 06/01/2030 **Start Date** 06/01/2028

Description

Reconductor the 1.5 mile section from Flat Shoals Road station to the Stonewall Tell loop - in point on the East Point - Union City 230kV Black line with 200C 1351 ACSS Martin conductor.

Replace limiting elements at Union City

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2031 to 2030

Change From Previous IRP

New Project

Estimated Cost – GPC	**REDACTED**
Estimated Cost – GTC	**REDACTED**
Estimated Cost – MEAG	**REDACTED**
Estimated Cost – DU	**REDACTED**
Estimated Cost – ITS Assigned*	**REDACTED**

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

ECHECONNEE-WELLSTON 115KV LINE REBUILD

Teams # 19627

Need Date 06/01/2030 **Start Date** 06/01/2023

Description

Rebuild approximately 11.8 miles of the Echeconnee - Wellston 115kV line with 200C 1351 ACSS conductor and the limiting elements along the line with higher ratings. Replace the Bus at North Warner Robins 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
Estimated Cost – ITS Assigned*	REDACTED

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

FARLEY (APC)-TAZEWELL 500KV

Teams # 21063

Need Date 06/01/2030 **Start Date** 12/01/2024

Description

Construct a new 500kV line from Farley (APC) to Tazewell substation, approximately 120 miles long. Construct a 5 breaker 500kV ring bus to loop in the Blacksmith - Talbot 500kV line, terminate the new Farley - Tazewell 500kV and Talbot #2 - Tazewell 500kV lines. Install a 500/230kV auto transformer to connect to the existing 230kV switchyard.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GAINESVILLE #2 - MCEVER ROAD 115 KV REBUILD

Teams # 12120

Need Date 06/01/2030 **Start Date** 12/31/2025

Description

Rebuild approximately 5.3 miles of the Gainesville #2 - McEver Rd 115kV line with 200C 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GLENWOOD SPRINGS - LAKE OCONEE 115KV LINE REBUILD

Teams # 20298

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Rebuild the North Eatonton Junction - Putnam Sawmill Junction line with 200C 1351 ACSS conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Advance to 2030 from 2033.

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

GOAT ROCK REACTORS INSTALLATION

Teams # 21128

Need Date 06/01/2030 **Start Date** 06/01/2028

Description

Install 1% series reactors on the Fortson - Goat Rock (Black) 230kV and Fortson - Goat Rock (White) 230kV.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GOLDENS CREEK - WARRENTON PRIMARY 230KV REBUILD

Teams # 19996

Need Date 06/01/2030 **Start Date** 06/01/2028

Description

Rebuild approximately 0.34 miles of the Goldens Creek - Warrenton Primary 230kV line from 100C 1 - 1351.5 ACSR Martin conductor to 200C 1351 ACCR Martin conductor or equivalent.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GORDON-SANDERSVILLE #1 115KV LINE REBUILD (DEEPSTEP-SAND #6)

Teams # 20428

Need Date 06/01/2030 **Start Date** 12/01/2023

Description

Rebuild the Deepstep - Robins Spring (7.6 miles) Robins Spring - Kaolin J (2.23mi), and Kaolin J - Sandersville #6 (0.66 miles) line sections of the Gordon - Sandersville #1 115kV line. Rebuild a total of 10.49 miles from 100C 336 ACSR to 100C ACSR 795 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
Estimated Cost – ITS Assigned*	REDACTED

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

GOSHEN AREA STRATEGIC SOLUTION

Teams # 21116

Need Date 06/01/2030 **Start Date** 06/01/2025

Description

Construct a 230kV switching station on the Waynesboro - Wilson 230kV line and a new 230kV line between the switching station and Goshen, approximately 12.3 miles. Provides an alternate power flow path into Goshen outside of the existing constrained Goshen - Vogtle corridor.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: BIG SMARR - TOMOCHICHI 500KV

Teams # 21073

Need Date 06/01/2030 **Start Date** 12/01/2024

Description

Construct a 500kV line from Big Smarr to Tomochichi, approximately 36 miles long. Make the necessary modifications at Big Smarr and Tomochichi to add breakers and terminate the line.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: BUZZARD ROOST - CAVENDER DRIVE 230KV NEW LINE

Teams # 21014

Need Date 06/01/2030 **Start Date** 06/01/2026

Description

GTC is building a new 7 mile 230kV line from Cavender Drive to Buzzard Roost with 200C 1351 ACSS 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: CAVENDER DRIVE 500/230KV AUTOBANK

Teams # 21013

Need Date 06/01/2030 **Start Date** 06/01/2026

Description

GTC will turn Cavender Drive into a 500/230kV station looping in the Villa Rica - Union City 500kV line, installing a 2016 MVA auto transformer.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EAST WATKINSVILLE 230 KV STATION MODIFICATION

Teams # 20375

Need Date 06/01/2030 **Start Date** 06/01/2028

Description

Replace the 1600A reactors at East Watkinsville on the Russell Dam 230kV line with larger size.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: POND FORK - MIDWAY 115KV LINE

Teams # 21131

Need Date 06/01/2030 **Start Date** 06/01/2026

Description

GTC: Construct approximately 6 miles of 115kV line with minimum 170C 1351 ACSS conductor from Gillsville Tap Junction to Pond Fork, utilizing the existing GTC owned portion of the North Jackson - Lawrence Smith 46kV ROW.
At Pond Fork, install a second 230/115kV 400MVA auto transformer and terminate the Pond Fork - Midway 115kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: ROCKVILLE - TIGER CREEK -WARTHEN 500KV LINES

Teams # 21077

Need Date 06/01/2030 **Start Date** 12/01/2024

Description

Build the new 500kV line from Rockville to Tiger Creek and Tiger Creek to Warthen, approximately 20 miles and 9 miles long respectively. Build a 500kV yard at Tiger Creek and install a 500/230kV auto transformer. Make all necessary accommodations at Warthen and Rockville for the new 500kV breakers.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: TALBOT #2 - TAZEWELL 500KV LINE

Teams # 21076

Need Date 06/01/2030 **Start Date** 12/01/2024

Description

Build a new 500kV line from Tazewell to Talbot #2, approximately 20 miles. Make all necessary accommodations at Tazewell and Talbot #2 for the new 500kV breakers and line termination.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: TIGER CREEK-ROCKVILLE-NORTH SPA 230KV PROJECT

Teams # 21094

Need Date 06/01/2030 **Start Date** 01/01/2025

Description

Build a new 4 - breaker 230kV ring bus at Rockville substation (no auto transformer to be added at this time).
Loop in the Eatonton Primary #2 - Wallace Dam 230kV line. Build a new line 230kV line to Tiger Creek.
Build a new 230kV line to North Spa.

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
Estimated Cost – ITS Assigned*	REDACTED

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

JEFFERSON ROAD - WINDER PRIMARY 115KV REBUILD

Teams # 20789

Need Date 06/01/2030 **Start Date** 06/01/2025

Description

Rebuild approximately 11 miles of the Jefferson Road - Russell - Richardson Street Junction segments of the Jefferson Road - Winder Primary 115kV line with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

KETTLE CREEK PRIMARY - PINE GROVE PRIMARY 115KV REBUILD

Teams # 20284

Need Date 06/01/2030 **Start Date** 06/02/2026

Description

Rebuild approximately 38.04 miles of 50C 4/0 ACSR conductor from the Pine Grove to the Pearson tap using 200C 1351 ACSS conductor.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2029 to 2030

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: ATHENA - WARRENTON 230KV CONVERSION

Teams # 21118

Need Date 06/01/2030 **Start Date** 06/01/2025

Description

Reconductor/rebuild and convert the 115kV lines from Athena - Union Point - Ray Place Road - Warrenton Primary to 230kV operation. Expand Athena 230kV bus for new line termination, construct 230kV bus at Union Point, and expand 230kV bus at Warrenton Primary for new line termination. Install 230/115kV auto transformers at Union Point Primary and Ray Place Road. Replace limiting network equipment at substations along the line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

NEW CAVENDER DRIVE - TRIBUTARY 230KV LINE

Teams # 20857

Need Date 06/01/2030 **Start Date** 06/01/2026

Description

Build a new 4 mile 230kV line from Cavender Drive to Tributary with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

NORTH SPA 230KV STRATEGIC PROJECT

Teams # 21093

Need Date 06/01/2030 **Start Date** 01/01/2025

Description

This project includes the following scope of work:
Build a new 230kV switching station north of Oasis in a ring bus configuration with 4 - breakers.
Loop in the East Social Circle - Oasis (White) 230kV line.
Build a new 230kV line to Cornish Mountain from North Spa. New 230kV line from Rockville 230kV will terminate in this station.

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
Estimated Cost – ITS Assigned*	REDACTED

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

TALLULAH LODGE - TOCCOA 115 KV REBUILD

Teams # 19995

Need Date 06/01/2030 **Start Date** 12/31/2025

Description

Rebuild the Tallulah Lodge - Toccoa 115kV Line with 100C 795 ACSR conductor (total of 10.3 miles). Replace limiting elements at Tallulah Lodge and Toccoa.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

TRIBUTARY - THORNTON RD 230KV REBUILD

Teams # 21098

Need Date 06/01/2030 **Start Date** 06/01/2027

Description

Rebuild the 2.8 mile Tributary - Thornton Road 230kV line with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

THOMASTON 230 NEW BUILD SUB

Teams # 20160

Need Date 11/01/2030 **Start Date** 01/01/2026

Description

Replace Thomaston 230/115kV 285MVA auto transformers C and D with 400MVA auto transformers. Install high side breakers to meet the 230kV bus differential standards and redesign 230kV bus to a breaker and a half configuration.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

BAINBRIDGE TRANSMISSION: EAST RIVER ROAD, EAST BAINBRIDGE

Teams # 18848

Need Date 12/31/2030 **Start Date** 06/01/2023

Description

This project will construct a new 115kV breaker and a half substation a mile north of the East Bainbridge substation. East Bainbridge will be simplified to a 115kV straight bus with two transmission lines for service to load, a generation interconnection point and a capacitor bank.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GLENWOOD SPRINGS 115KV CAP BANK

Teams # 19626

Need Date 12/31/2030 **Start Date** 01/01/2028

Description

Install a 115kV two stage 30MVAR capacitor bank at Glenwood Springs substation.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project advanced from 2031 to 2030.

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

EAST POINT - UNION CITY (WHITE) 230KV REBUILD

Teams # 20690

Need Date 05/01/2031 **Start Date** 06/01/2028

Description

Rebuild 5.49 miles of 100C 1590.0 ACSR Lapwing with 200C 1351.5 ACSS Martin 230kV line from Welcome All to Union City on the East Point - Union City 230kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

AVERY - HOPEWELL 115KV RECONDUCTOR

Teams # 19632

Need Date 06/01/2031 **Start Date** 01/01/2028

Description

Reconductor the Hopewell to Birmingham line section (approximately 3.3 miles) on the Avery - Hopewell 115kV line with 100C 1033 ACSR conductor. Replace jumper at Birmingham with 1590 AAC jumper.

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
Estimated Cost – ITS Assigned*	REDACTED

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

BOWEN #10 500/230KV AUTOBANK REPLACEMENT

Teams # 10811

Need Date 06/01/2031 **Start Date** 06/01/2025

Description

Replace the existing Bowen #10 1350 MVA 500/230kV auto transformer with a 2016 MVA 500/230kV auto transformer.

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
Estimated Cost – ITS Assigned*	REDACTED

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

HATCH - WADLEY 500 KV LINE STRATEGIC PROJECT

Teams # 20756

Need Date 06/01/2031 **Start Date** 07/03/2024

Description

Construct a new 500kV line from Hatch - Wadley Primary.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MEAG: PIO NONO 230/115KV AREA SOLUTION

Teams # 21099

Need Date 06/01/2031 **Start Date** 01/01/2025

Description

Build a 4 - breaker 230kV ring bus to terminate lines from Dorsett, South Griffin, and Big Grocery. Install a 400MVA auto transformer and build a 115kV yard to terminate a line from Broadway. Make all necessary modifications to accommodate all the 230kV and 115kV lines terminations.

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
Estimated Cost – ITS Assigned*	REDACTED

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

MEAG: SOUTH GRIFFIN 230/115KV BANK #5

Teams # 21114

Need Date 06/01/2032 **Start Date** 06/01/2030

Description

Replace 230/115kV 285MVA auto transformer #5 with 230/115kV 400MVA auto transformer at South Griffin.

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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: COLEMAN - MELDRIM 115KV LINE REBUILD

Teams # 20784

Need Date 06/01/2032 **Start Date** 06/01/2029

Description

Rebuild 3 miles of the Coleman - Meldrim 115kV line from Four Lakes to Meldrim with 200C 1351 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
Estimated Cost – ITS Assigned*	REDACTED

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

ARKWRIGHT BUS AND JUMPER REPLACEMENT

Teams # 20767

Need Date 06/01/2033 **Start Date** 06/01/2029

Description

Replace the 115kV bus at Arkwright with higher rating and replace the jumper on the Arkwright - Forrest Rd (Macon) 115kV line with at least 1590AAC.

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
Estimated Cost – ITS Assigned*	REDACTED

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

BAY CREEK - CONYERS 230KV LIMITING ELEMENT REPLACEMENT

Teams # 20758

Need Date 06/01/2033 **Start Date** 06/01/2031

Description

Replace equipment such as jumpers, switches, and traps at the Bay Creek, Rockdale, and Conyers substations with equipment capable of carrying 3000A.

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
Estimated Cost – ITS Assigned*	REDACTED

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

EVANS PRIMARY - THURMOND DAM (USA) #5 115KV REBUILD

Teams # 20793

Need Date 06/01/2033 **Start Date** 06/01/2029

Description

Rebuild approximately 5.45 miles of Euchee Creek - Thurmond Dam segment of the Evans Primary - Thurmond Dam (USA) #5 115kV line with 200C 1351 ACSS Martin conductor. Replace the main bus with a larger element at Thurmond Dam (USA).

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

EVANS PRIMARY - THURMOND DAM (USA) #6 115KV REBUILD

Teams # 20794

Need Date 06/01/2033 **Start Date** 06/01/2030

Description

Rebuild approximately 8.9 miles of the Evans Primary - Thurmond Dam (USA) #6 115kV line with 200C 1351 ACSS Martin conductor. Replace the main bus with a larger element at Thurmond Dam (USA).

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: CENTER PRIMARY - CLARKSBORO 230 KV REBUILD

Teams # 12217

Need Date 06/01/2033 **Start Date** 06/01/2028

Description

GTC to rebuild the Center Primary – Clarksboro Primary 230kV line (approx. 8.3 miles) with 200C 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

GTC: CLARKSBORO - WINDER PRIMARY 230KV REBUILD

Teams # 20773

Need Date 06/01/2033 **Start Date** 06/01/2029

Description

Rebuild approximately 14 miles of the Clarksboro - Winder 230kV line with 200C 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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EAST SOCIAL CIRCLE - SNELLVILLE 230KV EQUIPMENT UPGRADE

Teams # 12147

Need Date 06/01/2033 **Start Date** 06/01/2030

Description

Replace the 1200A switches at Snellville Primary with 3000A. Also, replace the 1200A line trap and switches at East Social Circle with 3000A on the East Social Circle - Snellville 230kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: EAST WALTON - MIDDLE FORK 500KV

Teams # 21075

Need Date 06/01/2033 **Start Date** 12/01/2024

Description

Construct a new 500kV line from East Walton to Middle Fork, approximately 45 miles long. Make all necessary accommodations for new 500kV breakers at East Walton and Middle Fork substations.

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
Estimated Cost – ITS Assigned*	REDACTED

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

GTC: SHOAL CREEK - SOUTH HALL 230KV REBUILD

Teams # 20791

Need Date 06/01/2033 **Start Date** 06/01/2029

Description

Rebuild approximately 7.9 miles of South Hall - Chestnut Mountain - Spout Springs Road segments of the Shoal Creek - South Hall 230kV line with 200C 1351 ACSS conductor. Also, replace 1 - AAC 1590 jumpers at South Hall with 2 - AAC 1590.

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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MCEVER ROAD - SHOAL CREEK 115KV REBUILD

Teams # 21053

Need Date 06/01/2033 **Start Date** 06/01/2030

Description

Rebuild the 2 - 4/0 copper part (approximately 2.9 miles) of the Gainesville Ferry - Lakeside WTP A line section, part of the McEver Road - Shoal Creek 115kV line, using 200C 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**
Estimated Cost – ITS Assigned*	**REDACTED**

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

MCGRAU FORD - MIDDLE FORK 500KV LINE PROJECT

Teams # 09661

Need Date 06/01/2033 **Start Date** 06/01/2026

Description

Construct a new approximately 64 mile 500kV line from McGrau Ford to 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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: MELDRIM BANK D REPLACEMENT

Teams # 20796

Need Date 06/01/2033 **Start Date** 06/01/2030

Description

Replace 300 MVA 230/115kV Bank D with 400 MVA Bank.

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
Estimated Cost – ITS Assigned*	REDACTED

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

THOMSON PRIMARY 230/115KV SECOND TRANSFORMER

Teams # 14222

Need Date 06/01/2033 **Start Date** 08/01/2025

Description

Install a second 400 MVA, 230/115kV auto transformer at Thomson Primary substation.

Supporting Statement

REDACTED

Change From Previous Ten Year Plan

Project delayed from 2031 to 2033

Change From Previous IRP

New Project

Estimated Cost – GPC	REDACTED
Estimated Cost – GTC	REDACTED
Estimated Cost – MEAG	REDACTED
Estimated Cost – DU	REDACTED
Estimated Cost – ITS Assigned*	REDACTED

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

WINDER PRIMARY 230KV BUS 1-2 PARALLEL BUS-TIE INSTALLATION

Teams # 20759

Need Date 06/01/2033 **Start Date** 06/01/2031

Description

Install a 2nd 230kV bus - tie breaker at the Winder Primary Station.

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
Estimated Cost – ITS Assigned*	REDACTED

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

PINE GROVE PRIMARY - WEST VALDOSTA 115 KV RECONDUCTOR

Teams # 10487

Need Date 12/31/2033 **Start Date** 12/31/2029

Description

Rebuild 3.7 miles of 100C 4/0 ACSR conductor with 200C 795 ACSS Drake on the Bemis - Pine Grove Primary section of the Pine Grove Primary - West Valdosta 115kV line.

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
Estimated Cost – ITS Assigned*	REDACTED

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

DAWSON CROSSING - GAINESVILLE #1 115 KV

Teams # 18700

Need Date 06/01/2034 **Start Date** 06/01/2032

Description

Replace the 500CU main bus at Gainesville #1 115kV with 3" Sch 40 AL Tube.

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
Estimated Cost – ITS Assigned*	REDACTED

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

SAV: LITTLE OGEECHEE 230/115KV BANK REPLACEMENT

Teams # 20787

Need Date 06/01/2034 **Start Date** 06/01/2030

Description

Replace SATX 280MVA auto transformer with 400MVA auto transformer.

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
Estimated Cost – ITS Assigned*	REDACTED

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

EVANS PRIMARY - THOMSON PRIMARY 115KV REBUILD

Teams # 17993

Need Date 12/31/2034 **Start Date** 01/01/2031

Description

Rebuild the existing 100C 336 ACSR conductor for the Thomson Primary to Pumpkin Center 115kV line section (approximately 5.28 miles), part of the Evans Primary - Thomson Primary 115kV line with 200C 1351 ACSS 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
Estimated Cost – ITS Assigned*	REDACTED

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

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.

It is not yet known where any new generation resources will be located after 2029. To balance load and generation in the base cases as load grows and existing fossil units are retired, it is necessary to make assumptions for the locations of generation to be added. When the cases are created, the “expansion units” listed in Table 9 are included as needed. The sites chosen for these units are locations where fossil units have been or are expected to be retired, since existing transmission connections are (or previously have been) adequate, and therefore are expected to cause minimal new constraints.

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

Table 9 Expansion Unit Locations

Case Type	APC (MW)	MPC (MW)	GPC (MW)	Total (MW)	Version Cases
Winter 2031	REDACTED	REDACTED	REDACTED	REDACTED	V1
Winter 2032	REDACTED	REDACTED	REDACTED	REDACTED	V1
Winter 2033	REDACTED	REDACTED	REDACTED	REDACTED	V1
Winter 2034	REDACTED	REDACTED	REDACTED REDACTED REDACTED	REDACTED	V1
Hot Weather 2030	REDACTED	REDACTED	REDACTED	REDACTED	V1
Hot Weather 2031	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V1
Hot Weather 2032	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V1
Hot Weather 2033	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V1
Hot Weather 2034	REDACTED	REDACTED	REDACTED REDACTED REDACTED	REDACTED	V1
Dusk Shoulder 2030	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V1
Dusk Shoulder 2031	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V1
Dusk Shoulder 2032	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V1
Dusk Shoulder 2033	REDACTED	REDACTED	REDACTED REDACTED REDACTED	REDACTED	V1
Dusk Shoulder 2034	REDACTED	REDACTED	REDACTED REDACTED REDACTED	REDACTED	V1
Winter 2032	REDACTED	REDACTED	REDACTED	REDACTED	V2
Winter 2033	REDACTED	REDACTED	REDACTED	REDACTED	V2
Winter 2034	REDACTED	REDACTED	REDACTED REDACTED	REDACTED	V2
Dusk Shoulder 2031	REDACTED	REDACTED	REDACTED	REDACTED	V2
Dusk Shoulder 2032	REDACTED	REDACTED	REDACTED	REDACTED	V2
Dusk Shoulder 2033	REDACTED	REDACTED	REDACTED	REDACTED	V2
Dusk Shoulder 2034	REDACTED	REDACTED	REDACTED	REDACTED	V2

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

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.

B. 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.

C. 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.

D. 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 10 PSSE Output Results

Version	File Location
v1C - STRE (2025-2034)	T:\TP-East\2024_TPE_Workplan\Screens\v1C
v2B - VAL (2025-2034)	T:\TP-East\2024_TPE_Workplan\Screens\v2B

Table 11 Thermal Problem Reports

Version	File Location
v1C - STRE (2025-2034)	T:\TP-East\2024_TPE_Workplan\Screens\V1C\Reports
v2B - VAL (2025-2034)	T:\TP-East\2024_TPE_Workplan\Screens\V2B\Reports\Final Report

Table 12 Voltage Problem Reports

Version	File Location
v1C - STRE (2025-2034)	T:\TP-East\2024_TPE_Workplan\Screens\V1C\Reports
v2B - VAL (2025-2034)	T:\TP-East\2024_TPE_Workplan\Screens\V2B\Reports\Final Report

Table 13 Study Reports

Study Type	File Location
P-Events	T:\TP-OATT_RegionalPlanning\Misc. Studies\24-001_TPL-001_Compliance
Extreme Events	T:\TP-OATT_RegionalPlanning\Misc. Studies\24-001_TPL-001_Compliance\ExtremeEvents
Northern Interface	T:\TP-OATT_RegionalPlanning\Interface\2024\NIS
Florida Interface	T:\TP-OATT_RegionalPlanning\Interface\2024\FIS
Nuclear FSAR - Hatch	T:\TP-OATT_RegionalPlanning\Misc. Studies\24-002_Annual_FSAR\Reports
Nuclear FSAR - Vogtle	T:\TP-OATT_RegionalPlanning\Misc. Studies\24-002_Annual_FSAR\Reports
Stability Studies	T:\TP-Stab\Compliance_(3.009-ACT)\TPL-001
Designation Studies	T:\TP-Strategic\2024

B. Generation Assumptions

Base Case Definitions

Table 14 Base Case Definitions

2024 Steady State Case Definitions							
Name	Prefix	Suffix	Load Level	Solar	Hydro	Battery	MISO Transfer
Summer Peak	S	SNWE	Summer Peak	On	On	Off	1000 S->N
Summer NS Regional Flows	S	NSEW	Summer Peak	On	On	Off	1000 N->S
Summer SN Max Regional Flows	S	SNmaxWE	Summer Peak	On	On	Off	2500 S->N
Summer NS Max Regional Flows	S	NSmaxEW	Summer Peak	On	On	Off	3000 N->S
Off Peak	O	SNWE	Off Peak (70%)	On	Motor	8hr Charge	1000 S->N
Off Peak NS Regional Flows	O	NSEW	Off Peak (70%)	On	Motor	8hr Charge	1000 N->S
Off Peak SN Max Regional Flows	O	SNmaxWE	Off Peak (70%)	On	Motor	8hr Charge	2500 S->N
Off Peak NS Max Regional Flows	O	NSmaxEW	Off Peak (70%)	On	Motor	8hr Charge	3000 N->S
Daylight Shoulder	D	SNWE	Shoulder (93%)	On	Motor	8hr Charge	1000 S->N
Daylight Shoulder NS Regional Flows	D	NSEW	Shoulder (93%)	On	Motor	8hr Charge	1000 N->S
Daylight Shoulder SN Max Regional Flows	D	SNmaxWE	Shoulder (93%)	On	Motor	8hr Charge	2500 S->N
Daylight Shoulder NS Max Regional Flows	D	NSmaxEW	Shoulder (93%)	On	Motor	8hr Charge	3000 N->S
Shoulder	H	SNWE	Shoulder (93%)	Off	50%	Off	1000 S->N
Shoulder NS Regional Flows	H	NSEW	Shoulder (93%)	Off	50%	Off	1000 N->S
Shoulder SN Max Regional Flows	H	SNmaxWE	Shoulder (93%)	Off	50%	Off	2500 S->N
Shoulder NS Max Regional Flows	H	NSmaxEW	Shoulder (93%)	Off	50%	Off	3000 N->S
Hot Weather	T	SNWE	Hot Weather (107%)	On	On	Discharge	1000 S->N
Hot Weather NS Regional Flows	T	NSEW	Hot Weather (107%)	On	On	Discharge	1000 N->S
Winter	W	SNWE	Winter Peak	Off	On	4hr Charge	1000 S->N
Winter NS Regional Flows	W	NSEW	Winter Peak	Off	On	4hr Charge	1000 N->S
Winter SN Max Regional Flows	W	SNmaxWE	Winter Peak	Off	On	4hr Charge	2500 S->N
Winter NS Max Regional Flows	W	NSmaxEW	Winter Peak	Off	On	4hr Charge	3000 N->S
Spring Peak	Z	SNWE	Spring Peak	On	On	Off	As Provided
Valley	L	SNWE	Spring Valley	Off	Motor /Pump	8hr Charge	As Provided
Fall Peak	F	SNWE	Spring Peak	On	On	Off	As Provided

Generation in Cases

Table 15 ITS Generation P_{max} in Cases

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
ADDISON 1 (WEST GA)	GPC	PPA-CT	REDACTED	REDACTED
ADDISON 2 (WEST GA)	GPC	PPA-CT	REDACTED	REDACTED
ADDISON 3 (WEST GA)	GPC	PPA-CT	REDACTED	REDACTED
REDACTED	**REDACTED**	**REDACTED**	REDACTED	REDACTED
ALBANY RENEWABLE ENERGY	GPC	PPA-Bio	REDACTED	REDACTED
ALLA DAM	GPC	Hydro	REDACTED	REDACTED
ALLIGATOR CREEK SOLAR	GPC	QF-Solar	REDACTED	REDACTED
AMERICUS BESS	Undesignated	Battery	REDACTED	REDACTED
AMERICUS 1	GPC	Hydro	REDACTED	REDACTED
AMERICUS 2	GPC	Hydro	REDACTED	REDACTED
AMERICUS 3	GPC	Hydro	REDACTED	REDACTED
REDACTED	**REDACTED**	**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	**REDACTED**	**REDACTED**	REDACTED REDACTED	REDACTED
BARTLETT'S FERRY 1 HY	GPC	Hydro	REDACTED	REDACTED
BARTLETT'S FERRY 2 HY	GPC	Hydro	REDACTED	REDACTED
BARTLETT'S FERRY 3 HY	GPC	Hydro	REDACTED	REDACTED
BARTLETT'S FERRY 4 HY	GPC	Hydro	REDACTED	REDACTED
BARTLETT'S FERRY 5 HY	GPC	Hydro	REDACTED	REDACTED
BARTLETT'S FERRY 6 HY	GPC	Hydro	REDACTED	REDACTED
REDACTED	**REDACTED**	**REDACTED**	REDACTED	REDACTED
BENNING SLR	GPC	Hydro	REDACTED	REDACTED
BIRD DOG PV	GPC	Hydro	REDACTED	REDACTED
BLACK WATER SOLAR	GPC	PPA Solar	REDACTED	REDACTED

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
BOULEVARD 1	GPC	Oil	REDACTED	REDACTED
BOWEN 1	GPC	Coal	REDACTED	REDACTED
BOWEN 2	GPC	Coal	REDACTED	REDACTED
BOWEN 3	GPC	Coal	REDACTED	REDACTED
BOWEN 4	GPC	Coal	REDACTED	REDACTED
BUFORD DAM 1+3	GPC	Hydro	REDACTED	REDACTED
BUFOR DAM 2	GPC	Hydro	REDACTED	REDACTED
BULLDOG PV	GPC	PPA Solar	REDACTED	REDACTED
CAMILLA SOLAR	GPC	PPA Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
CARTERS DAM 1	GPC	Hydro	REDACTED	REDACTED
CARTERS DAM 2	GPC	Hydro	REDACTED	REDACTED
CARTERS DAM 3	GPC	Hydro	REDACTED	REDACTED
CARTERS DAM 4	GPC	Hydro	REDACTED	REDACTED
REDACTED REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
COOL SPRINGS	GPC	PPA-Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DAHLBERG 10	GPC	PPA-CT	REDACTED	REDACTED
DAHLBERG 2	GPC	PPA-CT	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DAHLBERG 4	GPC	PPA-CT	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DAHLBERG 6	GPC	PPA-CT	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DAHLBERG 8	GPC	PPA-CT	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
DOUBLE RUN SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
DECATUR SOLAR	GPC	Hydro	REDACTED	REDACTED
DUBLIN B1	GPC	Bio	REDACTED	REDACTED
DOUGH PV	GPC	Hydro	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
EXELON HEARD 1	GPC	PPA-CT	REDACTED	REDACTED
EXELON HEARD 2	GPC	PPA-CT	REDACTED	REDACTED
EXELON HEARD 3	GPC	PPA-CT	REDACTED	REDACTED
EXELON HEARD 4	GPC	PPA-CT	REDACTED	REDACTED
EXELON HEARD 5	GPC	PPA-CT	REDACTED	REDACTED
EXELON HEARD 6	GPC	PPA-CT	REDACTED	REDACTED
FALL LANE SOLAR	GPC	Hydro	REDACTED	REDACTED
FLINT RIVER 1 HY	GPC	Hydro	REDACTED	REDACTED
FLINT RIVER 2 HY	GPC	Hydro	REDACTED	REDACTED
FLINT RIVER 3 HY	GPC	Hydro	REDACTED	REDACTED
FLINT RIVER SOLAR (DECATUR SLR)	GPC	PPA-Solar	REDACTED	REDACTED
FORT BENNING SOLAR	GPC	Solar	REDACTED	REDACTED
FORT GORDON 1 SOLAR	GPC	Solar	REDACTED	REDACTED
FORT STEWART SOLAR	GPC	Solar	REDACTED	REDACTED
FORT VALLEY STATE UNIVERSITY	GPC	Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
GASTON A	GPC	CT	REDACTED	REDACTED
GEORGE DAM 1	GPC	Hydro	REDACTED	REDACTED
GEORGE DAM 2	GPC	Hydro	REDACTED	REDACTED
GEORGE DAM 3	GPC	Hydro	REDACTED	REDACTED
GEORGE DAM 4	GPC	Hydro	REDACTED	REDACTED
GEORGIA RENEWABLE POWER FRANKLIN LLC	GPC	PPA-Bio	REDACTED	REDACTED
GEORGIA RENEWABLE POWER MADISON	GPC	PPA-Bio	REDACTED	REDACTED
GOAT ROCK 3 HY	GPC	Hydro	REDACTED	REDACTED
GOAT ROCK 4 HY	GPC	Hydro	REDACTED	REDACTED
GOAT ROCK 5 HY	GPC	Hydro	REDACTED	REDACTED
GOAT ROCK 6 HY	GPC	Hydro	REDACTED	REDACTED
GOAT ROCK 7 HY	GPC	Hydro	REDACTED	REDACTED
GOAT ROCK 8 HY	GPC	Hydro	REDACTED	REDACTED
GREEN POWER SOLUTIONS	GPC	PPA-Bio	REDACTED	REDACTED
HARRIS 1 - GPC	GPC	PPA-CC	REDACTED	REDACTED
HARRIS 2 - GPC	GPC	CC	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
HATCH 1	GPC	Nuclear	REDACTED	REDACTED

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
HATCH 2	GPC	Nuclear	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
HOBNAIL SOLAR	GPC	Hydro	REDACTED	REDACTED
INTERNATIONAL PAPER - FLINT RIVER	GPC	PPA-Bio	REDACTED	REDACTED
INTERNATIONAL PAPER - PORT WENTWORTH	GPC	PPA-Bio	REDACTED	REDACTED
KINGS BAY SOLAR	GPC	Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
LLOYD SHOALS 1 HY	GPC	Hydro	REDACTED	REDACTED
LLOYD SHOALS 2 HY	GPC	Hydro	REDACTED	REDACTED
LLOYD SHOALS 3 HY	GPC	Hydro	REDACTED	REDACTED
LLOYD SHOALS 4 HY	GPC	Hydro	REDACTED	REDACTED
LLOYD SHOALS 5 HY	GPC	Hydro	REDACTED	REDACTED
LLOYD SHOALS 6 HY	GPC	Hydro	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
LSS 50 MW - SIMON SOLAR FARM	GPC	PPA-Solar	REDACTED	REDACTED
LSS 50 MW - SOLAR D&D CAMILLA	GPC	PPA-Solar	REDACTED	REDACTED
MARINE CORPS LOGISTICS BASE	GPC	Solar	REDACTED	REDACTED
MAS GEORGIA LFG - PINE RIDGE	GPC	PPA-Bio	REDACTED	REDACTED
MAS GEORGIA LFG - RICHLAND CREEK	GPC	PPA-Bio	REDACTED	REDACTED
MCDONOUGH 4	GPC	CC	REDACTED	REDACTED
MCDONOUGH 5	GPC	CC	REDACTED	REDACTED
MCDONOUGH 6	GPC	CC	REDACTED	REDACTED
MCGRAU FORD BESS	GPC	Battery	REDACTED	REDACTED
MCINTOSH 10	GPC	CC	REDACTED	REDACTED
MCINTOSH 11	GPC	CC	REDACTED	REDACTED
MCINTOSH 1A	GPC	CT	REDACTED	REDACTED
MCINTOSH 2A	GPC	CT	REDACTED	REDACTED
MCINTOSH 3A	GPC	CT	REDACTED	REDACTED
MCINTOSH 4A	GPC	CT	REDACTED	REDACTED
MCINTOSH 5A	GPC	CT	REDACTED	REDACTED
MCINTOSH 6A	GPC	CT	REDACTED	REDACTED
MCINTOSH 7A	GPC	CT	REDACTED	REDACTED
MCINTOSH 8A	GPC	CT	REDACTED	REDACTED
MCMANUS 3A	GPC	CT	REDACTED	REDACTED

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
MCMANUS 3B	GPC	CT	REDACTED	REDACTED
MCMANUS 3C	GPC	CT	REDACTED	REDACTED
MCMANUS 4A	GPC	CT	REDACTED	REDACTED
MCMANUS 4B	GPC	CT	REDACTED	REDACTED
MCMANUS 4C	GPC	CT	REDACTED	REDACTED
MCMANUS 4D	GPC	CT	REDACTED	REDACTED
MCMANUS 4E	GPC	CT	REDACTED	REDACTED
MCMANUS 4F	GPC	CT	REDACTED	REDACTED
MID GEORGIA COGEN	GPC	PPA-Cogen	REDACTED	REDACTED
MONROE POWER	GPC	PPA-CT	REDACTED	REDACTED
MOODY AFB	GPC	Solar	REDACTED	REDACTED
MORGAN FALLS 1 HY	GPC	Hydro	REDACTED	REDACTED
MORGAN FALLS 2 HY	GPC	Hydro	REDACTED	REDACTED
MORGAN FALLS 3 HY	GPC	Hydro	REDACTED	REDACTED
MORGAN FALLS 4 HY	GPC	Hydro	REDACTED	REDACTED
MORGAN FALLS 5 HY	GPC	Hydro	REDACTED	REDACTED
MORGAN FALLS 6 HY	GPC	Hydro	REDACTED	REDACTED
MORGAN FALLS 7 HY	GPC	Hydro	REDACTED	REDACTED
MOSSY BRANCH	GPC	PPA-BES	REDACTED	REDACTED
NORTH HIGHLANDS 1 HY	GPC	Hydro	REDACTED	REDACTED
NORTH HIGHLANDS 2 HY	GPC	Hydro	REDACTED	REDACTED
NORTH HIGHLANDS 3 HY	GPC	Hydro	REDACTED	REDACTED
NORTH HIGHLANDS 4 HY	GPC	Hydro	REDACTED	REDACTED
OLIVER 1 HY	GPC	Hydro	REDACTED	REDACTED
OLIVER 2 HY	GPC	Hydro	REDACTED	REDACTED
OLIVER 3 HY	GPC	Hydro	REDACTED	REDACTED
OLIVER 4 HY	GPC	Hydro	REDACTED	REDACTED
PIEDMONT GREEN POWER	GPC	PPA-Bio	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - C&I: TANGLEWOOD SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - US 1: QUITMAN II SOLAR ENERGY CENTER	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - US 1: QUITMAN SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - US 1: SOUTHERN OAK SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - US 2: BROKEN SPOKE (Hickory Park)	GPC	PPA-Solar	REDACTED	REDACTED
REDI 1400 MW - US 2: COOL SPRINGS	GPC	PPA-Solar	REDACTED	REDACTED

PUBLIC DISCLOSURE

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Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
ROBINS AFB	GPC	Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
SCHERER 1	GPC	Coal	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
SCHERER 2	GPC	Coal	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
SCHERER 3	GPC	Coal	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
SIMON SOLAR	GPC	Solar	REDACTED	REDACTED
SINCLAIR 1 HY	GPC	Hydro	REDACTED	REDACTED
SINCLAIR 2 HY	GPC	Hydro	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
SONNY PV	GPC	Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
STAGECOACH SOLAR	GPC	Solar	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TALLULAH 1 HY	GPC	Hydro	REDACTED	REDACTED
TALLULAH 2 HY	GPC	Hydro	REDACTED	REDACTED
TALLULAH 3 HY	GPC	Hydro	REDACTED	REDACTED
TALLULAH 4 HY	GPC	Hydro	REDACTED	REDACTED
TALLULAH 5 HY	GPC	Hydro	REDACTED	REDACTED
TALLULAH 6 HY	GPC	Hydro	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
TERRORA 1 HY	GPC	Hydro	REDACTED	REDACTED
TERRORA 2 HY	GPC	Hydro	REDACTED	REDACTED
TIMBERLAND SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
TUGALO 1 HY	GPC	Hydro	REDACTED	REDACTED
TUGALO 2 HY	GPC	Hydro	REDACTED	REDACTED
TUGALO 3 HY	GPC	Hydro	REDACTED	REDACTED
TUGALO 4 HY	GPC	Hydro	REDACTED	REDACTED
VOGTLE 1	GPC	Nuclear	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
VOGTLE 2	GPC	Nuclear	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
VOGTLE 3	GPC	Nuclear	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
VOGTLE 4	GPC	Nuclear	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
WALLACE DAM 1 PS	GPC	Pump Storage Hydro	REDACTED	REDACTED
WALLACE DAM 2 PS	GPC	Pump Storage Hydro	REDACTED	REDACTED
WALLACE DAM 3 HY	GPC	Hydro	REDACTED	REDACTED
WALLACE DAM 4 HY	GPC	Hydro	REDACTED	REDACTED
WALLACE DAM 5 PS	GPC	Pump Storage Hydro	REDACTED	REDACTED
WALLACE DAM 6 PS	GPC	Pump Storage Hydro	REDACTED	REDACTED
WALTON COUNTY	GPC	PPA-CT	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
WANSLEY 1	GPC	Coal	REDACTED	REDACTED

Unit Name	Recipient	Fuel Type	PSSE Bus Number	Net Installed (MW)
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
WANSLEY 2	GPC	Coal	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
WARNER ROBINS 1	GPC	CT	REDACTED	REDACTED
WARNER ROBINS 2	GPC	CT	REDACTED	REDACTED
WASHINGTON COUNTY	GPC	PPA-CT	REDACTED	REDACTED
REDACTED REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
WASHINGTON COUNTY SOLAR	GPC	PPA-Solar	REDACTED	REDACTED
WILSON 1A	GPC	CT	REDACTED	REDACTED
WILSON 1B	GPC	CT	REDACTED	REDACTED
WILSON 1C	GPC	CT	REDACTED	REDACTED
WILSON 1D	GPC	CT	REDACTED	REDACTED
WILSON 1E	GPC	CT	REDACTED	REDACTED
WILSON 1F	GPC	CT	REDACTED	REDACTED
YATES 6 GAS	GPC	Oil/Gas Steam	REDACTED	REDACTED
YATES 7 GAS	GPC	Oil/Gas Steam	REDACTED	REDACTED
YONAH	GPC	Hydro	REDACTED	REDACTED

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 16 Generation Scenario (Unit Off) By Case Type

Generation Code	Description	Summer Peak	Shoulder	Off-Peak
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED		REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED		REDACTED
REDACTED	REDACTED	REDACTED		REDACTED
REDACTED	REDACTED	REDACTED		REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED		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	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	

Generation Code	Description	Summer Peak	Shoulder	Off-Peak
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED REDACTED	REDACTED	REDACTED	
REDACTED	REDACTED	REDACTED	REDACTED	
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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	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED		REDACTED

Generation Code	Description	Summer Peak	Shoulder	Off-Peak
REDACTED	REDACTED	REDACTED		REDACTED
REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

C. Strategic Projects

Ashley Park - Wansley 500kV Line
TEAMS 21062
Project Need Date: June 1, 2029

Executive Summary

The construction of the Ashley Park – Wansley 500kV line aims to address the evolving dynamics within the Georgia Integrated Transmission System (ITS), primarily driven by the changes in generation and forecasted load growth. This project involves the construction of a new ~30-mile 500 kV line from Ashley Park to Wansley as shown in Figure 4. Additionally, supplemental projects include Ashley Park Line Termination (GPC) and Wansley Line Termination (MEAG). This project will be done in conjunction with GTC: Tenaska – Wansley 500kV (TEAMS 21123).

The decision to undertake this project stems from the necessity to enhance available transmission capacity and mitigate thermal limits resulting from 500 kV contingencies under NERC TPL-001-5. This project will reduce flows and increase available capacity on various circuits, thereby alleviating or reducing thermal constraints on critical circuits under contingency scenarios. This solution is the result of joint planning efforts amongst the GA ITS Participants.

Figure 4 Area System Map

REDACTED

Compliance Statement

This project addresses problems associated with Category P1 events. These problems were identified as part of Southern Company's Transmission Planning process in compliance with NERC Standard TPL-001-5.

Background and Problem Description

The Ashley Park – Wansley 500kV line, in conjunction with the construction of the new GTC: Tenaska – Wansley 500kV line, effectively reduces flows and increases available capacity on overloaded circuits shown in Table 17. Table 18 indicates capacity increases on non-overloaded facilities. Both tables show capacity increases in relation to existing facility ratings.

Table 17 Load Flow Reductions on Overloaded Facilities

Facility Name	Facility Rating (MVA)	Loading Reduction
O'Hara - Charles 230kV	REDACTED	REDACTED
Loopers Farm - South Dalton	REDACTED	REDACTED
Villa Rica - Wansley 500kV	REDACTED	REDACTED
Dorsett - Thomaston 230kV	REDACTED	REDACTED
Bonaire Primary - Dorsett 230kV	REDACTED	REDACTED

Table 18 Capacity Increases on Non-Overloaded Facilities

Facility Name	Facility Rating (MVA)	Available Capacity Increase (MVA)	Loading Reduction
O'Hara - Ashley Park 500kV	REDACTED	REDACTED	REDACTED
O'Hara - Dresden 500kV	REDACTED	REDACTED	REDACTED
Dresden - Heard County 500kV	REDACTED	REDACTED	REDACTED
Heard County - Wansley 500kV	REDACTED	REDACTED	REDACTED
Heard County - Tenaska 500kV	REDACTED	REDACTED	REDACTED

In addition to solving thermal constraints and increasing capacity, the Ashley Park - Wansley 500kV along with the GTC: Tenaska – Wansley 500kV line provides improved voltage profiles for the west Georgia and greater Atlanta areas. Figures 5, 6, and 7 show the voltage difference on 500kV buses in the region with the addition of all new 500kV projects.

Figure 5 Voltage Improvements-Big Shanty

REDACTED

Figure 6 Voltage Improvements-Ohara

REDACTED

Figure 7 Voltage Improvements-Tomochichi

REDACTED

Study Assumptions

• Load Flow Cases: 2024 series V2
• Study Years: 2028 – 2034
• Case Seasons: Summer Peak, Off-Peak, Daylight Shoulder, Dusk Shoulder

Discussion of Alternatives

The Preferred Plan ($REDACTED) consists of:

- Construction of the Ashley Park – Wansley 500 kV Line (~30 miles) with (3) 100C 1113 ACSR conductor.
- Expand Ashley Park and Wansley Primary 500 kV yards to connect & terminate the new line.
- Installation of communication equipment and integration with EMS.

The preferred plan accomplishes the following:

1. **High-Capacity Corridor**: Establishes a new 500 kV line from Ashley Park to Wansley, enhancing system capacity in the metro area.
2. **Reduced Flows, Increased Capacity**: Decreases loading and increases available capacity on multiple circuits, improving system reliability.
3. **Supports Generation Expansion**: Facilitates integration of additional generation at existing facilities in area, promotes sustainability, and grid resilience.
4. **Operational Flexibility**: Provides significantly improved operational flexibility and reliability for system outages and future maintenance activities on existing facilities, particularly on the critical 500 kV system.

Alternate Plans

- **Alternate Plan 1**: Do Nothing ($REDACTED). This is not a feasible option to remain in compliance with NERC Standard TPL-001-5. In addition to the TPL compliance implications of this option, the severity and breadth of identified system constraints would result in in a severe degradation of service to Georgia Power customers.
- **Alternate Plan 2**: Brute Force ($REDACTED). This involves the direct replacement or rebuild of the facilities listed in Table 19.

Table 19 Brute Force Estimate

Facility Name	Mileage	Planning Grade Estimate
O'Hara - Charles 230kV Rebuild	14	REDACTED
Loopers Farm – South Dalton Jumper	N/A	REDACTED
Villa Rica - Wansley 500kV Rebuild	26	REDACTED
Dorsett – Thomaston 230kV Rebuild	39	REDACTED
Bonaire Primary – Dorsett 230kV Rebuild	17.6	REDACTED
Total	**97**	REDACTED

Alternate Plan 2 is not a feasible option given the following factors:

1. Accommodating and coordinating necessary outages to facilitate maintenance of existing facilities and the construction activities for system improvements
2. Timing and reduced reliability exposure to system given length of corridors

Additionally, the Brute Force alternative estimates do not reflect the full scope of all necessary work and costs that would be required along with any additional generation redispatch impacts associated with the numerous required outages.

Conclusion and Recommendations

The Ashley Park – Wansley 500kV New Line was selected because it solves identified thermal constraints, provides additional 500kV corridor for generation power transfers, and minimizes outage impacts to the transmission system during construction.

Farley (APC) – Tazewell 500kV Line

TEAMS 21063

Project Need Date: June 1, 2030

Executive Summary

The construction of the Farley (APC) – Tazewell 500 kV line aims to address the evolving dynamics within the Georgia Integrated Transmission System (ITS), primarily driven by changes in generation and forecasted load growth. This project involves the construction of a new ~120-mile 500 kV line from Farley (APC) to Tazewell as shown in Figure 8. Additionally, supplemental projects include Farley Line Termination (APC) and expansion of existing Tazewell 230kV station for new 500kV yard. This project will be done in conjunction with the GTC: Talbot #2 – Tazewell 500kV project (TEAMS 21076).

The decision to undertake this project stems from the necessity to enhance available transmission capacity and mitigate thermal limits resulting from 500 kV contingencies under NERC TPL-001-5. This project will reduce flows and increase available capacity on various circuits, thereby alleviating or reducing thermal constraints on critical circuits under contingency scenarios. This solution is the result of joint planning efforts amongst the GA ITS Participants.

Figure 8 Area System Map

REDACTED

Compliance Statement

This project addresses problems associated with Category P1 events. These problems were identified as part of Southern Company's Transmission Planning process in compliance with NERC Standard TPL-001-5.

Background and Problem Description

The Farley - Tazewell 500 kV line, in conjunction with the construction of the new GTC: Talbot #2 – Tazewell 500kV line, effectively reduces flows and increases available capacity on overloaded circuits shown in Table 20. Table 21 indicates capacity increases on non-overloaded facilities. Both tables show capacity increases in relation to existing facility ratings.

Table 20 Low Flow Reductions on Overloaded Facilities

Facility Name	Facility Rating (MVA)	Loading Reduction
Raccoon Creek 500/230kV Autotransformer A	REDACTED	REDACTED
Cotton Primary - Scooter 230kV	REDACTED	REDACTED
Daisy - West Valdosta 230kV	REDACTED	REDACTED
Mitchell - Raccoon Creek 230kV	REDACTED	REDACTED
Raccoon Creek - Scooter 230kV	REDACTED	REDACTED
Kawikee - South Columbus 115kV	REDACTED	REDACTED
Moultrie - Thomasville 115V	REDACTED	REDACTED
Albany Primary - Palmyra 115kV	REDACTED	REDACTED
Blakely Primary - Lower River Road 115kV	REDACTED	REDACTED
Lizard Lope - Arlington Primary 115kV	REDACTED	REDACTED
Fortson - Talbot #2 230kV	REDACTED	REDACTED
Fortson - Goat Rock 230kV (Black)	REDACTED	REDACTED
Fortson - Goat Rock 230kV (White)	REDACTED	REDACTED
Americus - Thrill Hill 115kV	REDACTED	REDACTED

Table 21 Capacity Increases on Non-Overloaded Facilities

Facility Name	Facility Rating (MVA)	Available Capacity Increase (MVA)	Loading Reduction
Arlington Primary - Giles 115kV	REDACTED	REDACTED	REDACTED
Cuthbert Primary - Kawikee 115kV	REDACTED	REDACTED	REDACTED

In addition to solving thermal constraints and increasing capacity, the Farley – Tazewell 500kV line along with the GTC: Talbot #2 – Tazewell 500kV line provides improved voltage profiles for the southwest and west Georgia areas. Figure 9 shows the improved voltage profile on key 500kV bus in southwest Georgia.

Figure 9 Voltage Profile

REDACTED

Study Assumptions

• Load Flow Cases: 2024 series V2
• Study Years: 2028 – 2034
• Case Seasons: Summer Peak, Off-Peak, Daylight Shoulder, Dusk Shoulder

Discussion of Alternatives

The Preferred Plan ($**REDACTED**) consists of:

- Construction of the Farley (APC) – Tazewell 500 kV Line (~120 miles) with (3) 100C 1113 ACSR conductor.
- Expand existing Tazewell 230kV yard to install new 500/230kV autotransformer and create new 5 breaker 500kV ring. 500kV Ring will have line terminations to Farley (APC), Talbot #2, Blacksmith, and Talbot.
- Terminate 500kV line at Farley (APC)
- Installation of communication equipment and integration with EMS.

The preferred plan accomplishes the following:

1. **High-Capacity Corridor**: Establishes a new 500 kV line from Farley to Tazewell, enhancing system capacity from South to North.
2. **Reduced Flows, Increased Capacity**: Decreases loading and increases available capacity on multiple circuits, improving system reliability.
3. **Supports Generation Expansion**: Facilitates integration of additional generation at existing facilities along with new solar facilities, promotes sustainability, and grid resilience.
4. **Operational Flexibility:** Provides significantly improved operational flexibility and reliability for system outages and future maintenance activities on existing facilities, particularly on the critical 500 kV system.

Alternate Plans

- **Alternate Plan 1:** Do nothing ($REDACTED). This is not a viable option to remain in compliance with NERC TPL-001-5. In addition to the TPL compliance implications of this option, the severity and breadth of identified system constraints would result in in a severe degradation of service to Georgia Power customers.
- **Alternate Plan 2:** Brute Force ($REDACTED). This involves the direct replacement or rebuild of the facilities listed in Table 22.

Table 22 Brute Force Estimates

Facility Name	Rebuild Line Length (Miles)	Planning Grade Estimate
Raccoon Creek 500/230kV Autotransformer A	N/A	REDACTED
Cotton Primary - Scooter 230kV	7.25	REDACTED
Daisy - West Valdosta 230kV	15.9	REDACTED
Mitchell - Raccoon Creek 230kV	7.68	REDACTED
Raccoon Creek - Scooter 230kV	8.21	REDACTED
Kawikee - South Columbus 115kV	9	REDACTED
Moultrie - Thomasville 115V	13.1	REDACTED
Albany Primary - Palmyra 115kV	1.92	REDACTED
Blakely Primary - Lower River Road 115kV	9.5	REDACTED
Lizard Lope - Arlington Primary 115kV	21.6	REDACTED
Fortson - Talbot #2 230kV	14	REDACTED
Fortson - Goat Rock 230kV (Black)	9.9	REDACTED
Fortson - Goat Rock 230kV (White)	10	REDACTED
Americus - Thrill Hill 115kV	19.11	REDACTED
Total	**147.17**	REDACTED

Alternate Plan 2 is not a feasible option given the following factors:

1. Accommodating and coordinating necessary outages to facilitate maintenance of existing facilities and the construction activities for system improvements
2. Timing and reduced reliability exposure to system given length of corridors
3. Lack of solution robustness to facilitate power transfers from south Georgia to north Georgia driven by increased solar generation and load growth

Additionally, the Brute Force alternative estimates do not reflect the full scope of all necessary work and costs that would be required along with any additional generation redispatch impacts associated with the numerous required outages.

Conclusion and Recommendations

Although the Preferred Plan is not the least cost plan, it was selected because it solves identified thermal constraints, provides additional 500kV corridor for solar generation power transfers, and minimizes outage impacts to the transmission system during construction.

Hatch – Wadley 500kV Line

TEAMS 20756

Project Need Date: June 1, 2031

Executive Summary

The construction of the Hatch – Wadley Primary 500 kV Line aims to address the evolving dynamics within the Georgia Integrated Transmission System (ITS), primarily driven by the increasing penetration of renewable generation plants and forecasted load growth. This project involves the construction of a new ~65-mile 500 kV line from Hatch to Wadley Primary as shown in Figure 10. Additionally, supplemental projects include Hatch Line Termination (GPC) and Wadley Primary Line Termination (MEAG).

The decision to undertake this project stems from the necessity to enhance available transmission capacity and mitigate potential thermal limits resulting from 500 kV contingencies under solar expansion scenarios. The 2023 ITS solar sensitivity study identified numerous benefits associated with the Hatch – Wadley 500 kV line, including providing an additional high-capacity corridor from South to North for solar penetration level of **REDACTED**. Furthermore, this project is anticipated to reduce flows and increase available capacity on various circuits, thereby alleviating or reducing thermal constraints on critical circuits under solar expansion scenarios. This solution is the result of joint planning efforts amongst the GA ITS Participants.

Figure 10 Area System Map

REDACTED

Compliance Statement

This project addresses problems associated with Category P1 events. These problems were identified as part of Southern Company's Transmission Planning process in compliance with NERC Standard TPL-001-5.

Background and Problem Description

The Hatch – Wadley 500 kV line effectively reduces flows and increases available capacity on the below circuits. Table 23 indicates the reduction in percent MVA of existing flow on the lines. Table 24 indicates capacity increases in percent MVA and total MVA in relation to existing line ratings. Figure 11 provides a regional overview highlighting some of the impacted areas experiencing flow reductions and capacity increases.

Table 23 Load Flow Reductions

Monitored Facility	Rating (MVA)	Flow reductions (% MVA)
Bonaire Primary - Kathleen 230 kV	REDACTED	REDACTED
Branch – Glenwood Springs 230 kV	REDACTED	REDACTED
Branch - Tiger Creek (Black) 230 kV	REDACTED	REDACTED
Branch - Tiger Creek (White) 230 kV	REDACTED	REDACTED
Branch - Warrenton Primary 230 kV	REDACTED	REDACTED
Eatonton Primary - Porterdale Primary 230 kV	REDACTED	REDACTED
Hatch - Vidalia 230 kV	REDACTED	REDACTED
Hatch 500/230 kV Bank #10	REDACTED	REDACTED
Kathleen - Pitts 230 kV	REDACTED	REDACTED
North Dublin - Wadley Primary 230 kV	REDACTED	REDACTED
North Tifton - Pitts 230 kV	REDACTED	REDACTED
Sandersville #1 - Wadley Primary 230 kV	REDACTED	REDACTED
Thomson 500/230 kV Bank D	REDACTED	REDACTED
Tiger Creek – Wadley Primary 230 kV	REDACTED	REDACTED
Vidalia - Wadley Primary (White) 230 kV	REDACTED	REDACTED
Vidalia 230 kV Bus Tie	REDACTED	REDACTED
Wadley 500/230 kV Bank C	REDACTED	REDACTED
Wadley 500/230 kV LS Breaker #1	REDACTED	REDACTED
Wadley 500/230 kV LS Breaker #2	REDACTED	REDACTED
Mosley – Wadley 230 kV	REDACTED	REDACTED
Mosley – Vidalia 230 kV	REDACTED	REDACTED

Table 24 Capacity Increases

Monitored Facility	Rating (MVA)	Increase in Available Capacity (% MVA)	Increase in Available Capacity (MVA)
Hatch - Vidalia 230 kV	REDACTED	REDACTED	REDACTED
Hatch 500/230 kV Bank #10	REDACTED	REDACTED	REDACTED
Thomson 500/230 kV Bank D	REDACTED	REDACTED	REDACTED
Tiger Creek - Wadley Primary 230 kV	REDACTED	REDACTED	REDACTED
Vidalia - Wadley Primary (White) 230 kV	REDACTED	REDACTED	REDACTED
Vidalia 230 kV Bus Tie	REDACTED	REDACTED	REDACTED
Wadley 500/230 kV Bank C	REDACTED	REDACTED	REDACTED
Wadley 500/230 kV LS Breaker #1	REDACTED	REDACTED	REDACTED
Wadley 500/230 kV LS Breaker #2	REDACTED	REDACTED	REDACTED
Mosley – Wadley 230 kV	REDACTED	REDACTED	REDACTED
Mosley – Vidalia 230 kV	REDACTED	REDACTED	REDACTED

Figure 11 Impacted Area

REDACTED

Study Assumptions

- Load Flow Cases: 2023 series V1 and V2
- Study Years: 2028 – 2033
- Case Seasons: Summer Peak, Off-Peak, Daylight Shoulder, Dusk Shoulder

Discussion of Alternatives

The Preferred Plan ($REDACTED) consists of:

- Construction of the Hatch – Wadley Primary 500 kV Line (~65 miles) with (3) 100C 1113 ACSR conductor.
- Expand Hatch and Wadley Primary 500 kV yards to connect & terminate the new line.
- Installation of communication equipment and integration with EMS.

The preferred plan accomplishes the following:

1. **High-Capacity Corridor**: Establishes a new 500 kV line from Hatch to Wadley Primary, enhancing system capacity from South to North.
2. **Reduced Flows, Increased Capacity**: Decreases loading and increases available capacity on multiple circuits, improving system reliability.
3. **Supports Solar Expansion**: Facilitates integration of solar generation, promotes sustainability, and grid resilience.
4. **Operational Flexibility**: Provides significantly improved operational flexibility and reliability for system outages and future maintenance activities on existing facilities.

Alternate Plans

- **Alternate Plan 1:** Do nothing ($REDACTED). The trend of increasing penetration of renewable (solar) generation plants on the Georgia Integrated Transmission System (ITS), and the resulting displacement of traditional fossil-fueled resources (particularly older coal facilities) is changing flow patterns on the system. These changes in addition to evolving interregional flow patterns and forecasted load growth are resulting in transmission congestion. If left unaddressed the system will not be able to facilitate future growth and maintain reliability requirements. This will introduce potential delays and limits until transmission improvements are identified and completed on an individual basis at the time of interconnection.

Conclusion and Recommendations

The Hatch – Wadley Primary 500 kV line project represents a strategic investment in the future reliability and efficiency of the Georgia Integrated Transmission System (ITS). Given the anticipated benefits, the GA ITS Solar Sensitivity Study team recommends proceeding with the implementation of the Hatch – Wadley 500kV project as part of the phased approach outlined in the 2023 Solar Sensitivity Analysis Results and Recommendations as presented to the Joint Committee on January 25, 2024.

McGrau Ford – Middle Fork 500kV Line

TEAMS 09661

Project Need Date: June 1, 2033

Executive Summary

The construction of the McGrau Ford - Middle Fork 500kV transmission line is intended to address the unprecedented, forecasted load growth and the increase of solar penetration in the state of Georgia. The project builds a new 65 miles of 500kV line from Middle Fork to McGrau Ford as shown in Figure 12. Additionally, supplemental projects include the expansion of the 500kV yard at McGrau Ford (GPC) and the construction of a new 500kV yard at Middle Fork (GTC) for the line termination.

This project mitigates multiple thermal constraints under NERC TPL-001-5 and increases capacity in the northeast area of Georgia in addition to improving overall voltage profile of the area under key 500kV contingencies and unit out generation scenarios. Solar sensitivity studies, **REDACTED** of solar penetration, showed that this new 500kV line increases capacity in transmission elements under solar expansion scenarios improving the transfer capability of generation in the area. This project will be done in conjunction with the GTC: East Walton-Middle Fork 500kV (TEAMS 21075).

Figure 12 Area System Map

REDACTED

Compliance Statement

This project addresses problems associated with Category P1 events. These problems were identified as part of Southern Company's Transmission Planning process in compliance with NERC Standard TPL-001-5.

Background and Problem Description

The McGrau Ford – Middle Fork 500kV in conjunction with the new GTC: East Walton-Middle Fork 500kV line project has multiple drivers: it alleviates thermal constraints, increases capacity in the area and provides voltage support for non-converge cases.

Thermal Impacts:

The McGrau Ford-Middle Fork 500kV line effectively reduces flow and increases capacity on the circuits listed below. Table 25 denotes flow reductions in percent difference between flow currently on the circuits compared to when the McGrau Ford – Middle Fork 500kV project is included. Table 26 denotes increases in available capacity compared to the MVA rating of the circuit.

Table 25 Load Flow Reductions

Monitored Facility	Rating (MVA)	Base case, post-contingency loading (MVA)	Post-contingency loading with MGF-MF 500kV (MVA)	Flow reductions (% MVA)
South Hall 500/230kV LS Breaker #2	REDACTED	REDACTED	REDACTED	REDACTED
Norcross – South Hall 500kV	REDACTED	REDACTED	REDACTED	REDACTED
South Hall 500/230kV Bank A *	REDACTED	REDACTED	REDACTED	REDACTED
South Hall 500/230kV LS Breaker #1	REDACTED	REDACTED	REDACTED	REDACTED
South Hall – Winder Primary 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Middle Fork – Unity 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Center Primary – Commerce Primary 115kV *	REDACTED	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Dawson Crossing – Nelson (White) 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (White) 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Dawson Crossing 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Bio – Pooles Creek 115kV *	REDACTED	REDACTED	REDACTED	REDACTED
Avalon Junction – Pooles Creek 115kV *	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (White) 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank C	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (Black) 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank D	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (Black) 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank C	REDACTED	REDACTED	REDACTED	REDACTED
Athens – East Watkinsville 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Buford #3 - Suwanee	REDACTED	REDACTED	REDACTED	REDACTED
Shoal Creek 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Northwinds – Ocee 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Buford Dam – Shoal Creek 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 – McEver Road 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Alpharetta – Northwinds 230kV	REDACTED	REDACTED	REDACTED	REDACTED
East Watkinsville 230/115kV Bank A *	REDACTED	REDACTED	REDACTED	REDACTED
Alpharetta – Glaze Drive 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Dawson Crossing – Nelson (Black) 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Norcross – Ocee 230kV **	REDACTED	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank D	REDACTED	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank E	REDACTED	REDACTED	REDACTED	REDACTED

* Indicates constraint seen in 2024 V2B screen, addressed by McGrau Ford – Middle Fork 500kV project

Note: Norcross-Ocee 230kV post MVA exceeds the line rating due to the voltage on the line being higher under contingency causing the MVA to jump above the rating. However, the post contingency amps are* ***REDACTED whereas the circuit rating is ***REDACTED***. The line loading is calculated off amps not the MVA, and the loading is at ***REDACTED.***

Table 26 Capacity Increases

Monitored Facility	Rating (MVA)	Increase in Available Capacity (% MVA)	Increase in Available Capacity (MVA)
Norcross – South Hall 500kV	REDACTED	REDACTED	REDACTED
South Hall 500/230kV Bank A	REDACTED	REDACTED	REDACTED
South Hall 500/230kV LS Breaker #2	REDACTED	REDACTED	REDACTED
South Hall 500/230kV LS Breaker #1	REDACTED	REDACTED	REDACTED
South Hall – Winder Primary 230kV	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank D	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank E	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 230kV	REDACTED	REDACTED	REDACTED
Dawson Crossing 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (White) 230kV	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank C	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (Black) 230kV	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank D	REDACTED	REDACTED	REDACTED
Bio – Pooles Creek 115kV	REDACTED	REDACTED	REDACTED
Avalon Junction – Pooles Creek 115kV	REDACTED	REDACTED	REDACTED
Alpharetta – Northwinds 230kV	REDACTED	REDACTED	REDACTED
Northwinds – Ocee 230kV	REDACTED	REDACTED	REDACTED
Center Primary – Commerce Primary 115kV	REDACTED	REDACTED	REDACTED
Alpharetta – Glaze Drive 230kV	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (White) 115kV	REDACTED	REDACTED	REDACTED
Norcross – Ocee 230kV	REDACTED	REDACTED	REDACTED
East Watkinsville 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Middle Fork – Unity 115kV	REDACTED	REDACTED	REDACTED
Dawson Crossing – Nelson (White) 115kV	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank C	REDACTED	REDACTED	REDACTED
Shoal Creek 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (Black) 115kV	REDACTED	REDACTED	REDACTED
Gainesville #2 – McEver Road 115kV	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 115kV	REDACTED	REDACTED	REDACTED
Buford Dam – Shoal Creek 115kV	REDACTED	REDACTED	REDACTED
Athens – East Watkinsville 115kV	REDACTED	REDACTED	REDACTED
Buford #3 - Suwanee	REDACTED	REDACTED	REDACTED
Dawson Crossing – Nelson (Black) 115kV	REDACTED	REDACTED	REDACTED

Voltage Impact:

In addition to alleviating thermal constraints and increasing capacity, the McGrau Ford-Middle Fork 500kV line provides VAR support to the northeast area. The McGrau Ford – Middle Fork 500kV project along with the GTC: East Walton – Middle Fork 500kV project alleviates the severe voltage depression issues seen in many different scenarios, due to the voltage support provided by the connection of the northern 500kV system. The base 2024 V2B cases had the stability-driven +150/-150 STATCOMs at McGrau Ford 230kV and Middle Fork 230kV placed online to alleviate non-converged case issues in later years.

Table 27 indicates post-contingency voltages in worst case scenarios, and equivalent amount of reactive support required at South Hall 500kV indicated as comparison to the level of voltage support that the McGrau Ford – Middle Fork 500kV project provides to the area.

Table 27 Post-contingency Voltages in Worst Case Scenarios

Case	Post-Contingency Voltage (PU)	Voltage with McGrau Ford – Middle Fork 500kV (PU)	Equivalent amount of reactive support (MVAR)
REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED	REDACTED

The results in tables 28 and 29 show the post-contingency voltage results for non-converge base cases versus the McGrau Ford-Middle Fork 500kV line being in service with the mentioned STATCOMs OFF and ON, respectively.

Table 28 provides the voltage comparison of the North GA 500kV system in the version 2B load flow cases with the McGrau Ford – Middle Fork 500kV line in service and stability STATCOMs off:

Table 28 Voltage Results STATCOM OFF

Bus	Case	Base V2B Post-Contingency Voltage (PU) / (kV)		Post Contingency Voltage with McGrau Ford – Middle Fork 500kV (PU) / (kV)		Difference (PU) / (kV)	
Big Shanty 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Norcross 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bull Sluice 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Klondike 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ohara 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ashley Park 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Dresden 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Union City 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Villa Rica 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McGrau Ford 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
South Hall 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
East Walton 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Figures 13 through 16 show the post-contingency voltage for base cases vs the McGrau Ford-Middle Fork 500kV line being in service and the STATCOMs off for several 500kV facilities in North Georgia.

Figure 13 Voltage Profile-Norcross-STATCOM Off

REDACTED

Figure 14 Voltage Profile-Villa Rica-STATCOM Off

REDACTED

Figure 15 Voltage Profile-South Hall-STATCOM Off

REDACTED

Figure 16 Voltage Profile-McGrau Ford-STATCOM Off

REDACTED

Table 29 provides the voltage comparison of the North GA 500kV system in the version 2B load flow base cases with the McGrau Ford – Middle Fork 500kV line in service with stability STATCOMs on:

Table 29 Voltage Results STATCOM ON

Bus	Case	Base V2B Post-Contingency Voltage (PU) / (kV)		Post Contingency Voltage with McGrau Ford – Middle Fork 500kV (PU) / (kV)		Difference (PU) / (kV)	
Big Shanty 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Norcross 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Bull Sluice 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Klondike 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ohara 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Ashley Park 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Dresden 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Union City 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Villa Rica 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
McGrau Ford 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
South Hall 500kV	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
East Walton 500kV	REDACTED REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	REDACTED REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Figures 17 through 20 show the post-contingency voltage for base cases vs the McGrau Ford-Middle Fork 500kV line being in service and the STATCOMs on for several 500kV facilities in North Georgia.

Figure 17 Voltage Profile-Villa Rica-STATCOM ON

REDACTED

Figure 18 Voltage Profile-Norcross-STATCOM Off

REDACTED

Figure 19 Voltage Profile-McGrau Ford-STATCOM Off

REDACTED

Figure 20 Voltage Profile-South Hall-STATCOM Off

REDACTED

Figures 21 through 24 show the improved voltage profile on key buses with all new 500kV projects in place.

Figure 21 Voltage Profile-Norcross

REDACTED

Figure 22 Voltage Profile-McGrau Ford

REDACTED

Figure 23 Voltage Profile-East Walton

REDACTED

Figure 24 Voltage Profile-Rockville

REDACTED

Solar Sensitivity Analysis

Studies were performed to analyze the increase of capacity and flow reduction in the area with the McGrau Ford-Middle Fork 500kV line in service for Solar Sensitivity cases. Table 30 shows the loading of several lines and elements in the northeast area for solar sensitivity cases with the line out of service and in service. Table 31 shows the increase of capacity for these lines and elements with the line in service.

Table 30 Load Flow Reductions – Solar Sensitivity

Monitored Facility	Rating (MVA)	SS Base case, post-contingency loading (MVA)	SS post-contingency loading with MGF-MF 500kV (MVA)	Flow reductions (% MVA)
South Hall 500/230kV LS Breaker #2	REDACTED	REDACTED	REDACTED	REDACTED
Norcross – South Hall 500kV	REDACTED	REDACTED	REDACTED	REDACTED
South Hall 500/230kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
South Hall 500/230kV LS Breaker #1	REDACTED	REDACTED	REDACTED	REDACTED
South Hall – Winder Primary 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Bull Sluice - Norcross 500kV	REDACTED	REDACTED	REDACTED	REDACTED
Middle Fork – Unity 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Center Primary – Commerce Primary 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (White) 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Glaze Drive – Norcross 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Carters Dam – Nelson 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank C	REDACTED	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (White) 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (Black) 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank C	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank D	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (Black) 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Buford Dam – Shoal Creek 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Dawson Crossing 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Buford #3 - Suwanee	REDACTED	REDACTED	REDACTED	REDACTED
Shoal Creek 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Gainesville #2 – McEver Road 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Northwinds – Ocee 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Alpharetta – Northwinds 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 115kV	REDACTED	REDACTED	REDACTED	REDACTED
Norcross – Ocee 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Shoal Creek – South Hall 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Alpharetta – Glaze Drive 230kV	REDACTED	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank D	REDACTED	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank E	REDACTED	REDACTED	REDACTED	REDACTED
East Watkinsville 230/115kV Bank A	REDACTED	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 230kV	REDACTED	REDACTED	REDACTED	REDACTED

Table 31 Capacity Increase – Solar Sensitivity

Monitored Facility	Rating (MVA)	Increase in Available Capacity (% MVA)	Increase in Available Capacity (MVA)
Norcross – South Hall 500kV	REDACTED	REDACTED	REDACTED
South Hall 500/230kV Bank A	REDACTED	REDACTED	REDACTED
South Hall 500/230kV LS Breaker #2	REDACTED	REDACTED	REDACTED
South Hall 500/230kV LS Breaker #1	REDACTED	REDACTED	REDACTED
Bull Sluice - Norcross 500kV	REDACTED	REDACTED	REDACTED
South Hall – Winder Primary 230kV	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank D	REDACTED	REDACTED	REDACTED
Norcross 500/230kV Bank E	REDACTED	REDACTED	REDACTED
Glaze Drive – Norcross 230kV	REDACTED	REDACTED	REDACTED
Carters Dam – Nelson 230kV	REDACTED	REDACTED	REDACTED
Shoal Creek – South Hall 230kV	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (White) 230kV	REDACTED	REDACTED	REDACTED
Gainesville #2 – South Hall (Black) 230kV	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank C	REDACTED	REDACTED	REDACTED
Gainesville #2 230/115kV Bank D	REDACTED	REDACTED	REDACTED
Norcross – Ocee 230kV	REDACTED	REDACTED	REDACTED
Alpharetta – Northwinds 230kV	REDACTED	REDACTED	REDACTED
Northwinds – Ocee 230kV	REDACTED	REDACTED	REDACTED
Alpharetta – Glaze Drive 230kV	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (White) 115kV	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank C	REDACTED	REDACTED	REDACTED
Bio 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Shoal Creek 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Center Primary – Commerce Primary 115kV	REDACTED	REDACTED	REDACTED
Dawson Crossing 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Gainesville #1 – Gainesville #2 (Black) 115kV	REDACTED	REDACTED	REDACTED
Gainesville #2 – McEver Road 115kV	REDACTED	REDACTED	REDACTED
Middle Fork – Unity 115kV	REDACTED	REDACTED	REDACTED
East Watkinsville 230/115kV Bank A	REDACTED	REDACTED	REDACTED
Buford Dam – Shoal Creek 115kV	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 230kV	REDACTED	REDACTED	REDACTED
Buford #3 - Suwanee	REDACTED	REDACTED	REDACTED
Athena – East Watkinsville 115kV	REDACTED	REDACTED	REDACTED

Study Assumptions

Base Case Thermal Study
- Load Flow Cases: 2024 series v2b
- Study Years: 2031-2034
- Case Seasons: Summer Peak, Off-Peak, Daylight Shoulder, Dusk Shoulder

Voltage Comparison Study
- Load Flow Cases: 2024 series v2b
- Study Years: 2033-2034
- Case Seasons: Summer Peak - Only non-converged base cases were evaluated

Solar Sensitivity Thermal Study
- Load Flow Cases: 2024 series v2b
- Study Years: 2031-2034
- Solar Penetration: **REDACTED**
- Case Seasons: Summer Peak, Off-Peak, Daylight Shoulder, Dusk Shoulder

Discussion of Alternatives

The Preferred Plan ($**REDACTED**) includes the following:
- Construction of the McGrau Ford-Middle Fork 500 kV Line (approximately 65 miles) with (3) 100C 1113 ACSR conductor.
- Expand the McGrau Ford 500kV yard and convert to a ring bus and build a 500kV yard at Middle Fork to terminate the new line.
- Installation of communication equipment and integration with EMS.

The preferred plan accomplishes the following:
1. **High-Capacity Corridor**: Establishes a new 500 kV line from McGrau Ford to Middle Fork, connecting the 500kV system in the north of Georgia enhancing the system capacity.
2. **Reduced Flows and Increased Capacity**: Decreases flows and increases available capacity on multiple circuits, improving system reliability in the northeast.
3. **Supports Generation Expansion**: Facilitates integration of additional generation at existing facilities along with new solar facilities, promotes sustainability, and grid resilience.
4. **Operational Flexibility**: Provides significantly improved operational flexibility and reliability for system outages and future maintenance activities on existing facilities, particularly on the critical 500 kV system.

Alternate Plans
- **Alternate Plan 1**: Do nothing ($**REDACTED**). This is not a viable option to remain in compliance with NERC TPL-001-5. In addition, the trend of increasing penetration of renewable (solar) generation plants on the Georgia Integrated Transmission System (ITS), and the resulting displacement of traditional fossil-fueled resources (particularly older coal facilities) is changing flow patterns on the system. These changes in addition to evolving interregional flow patterns and forecasted load growth are resulting in transmission congestion. If left unaddressed the system will not be able to facilitate future growth and maintain reliability requirements. This will introduce potential delays and limits until transmission improvements are identified and completed on an individual basis at the time of interconnection.

- **Alternate Plan 2:** Brute Force (Total of $REDACTED). This involves the direct replacement or rebuild of the facilities noted in Table 32.

Table 32 Brute Force Estimates

Facility Name	Rebuild Line Length (Miles)	Planning Grade Estimate
Avalon Junction – Pooles Creek – Bio 115kV rebuild	20.5	REDACTED
Center Primary – Commerce Primary 115kV rebuild	17	REDACTED
East Watkinsville 230/115kV new auto transformer	N/A	REDACTED
Norcross – Ocee 230kV rebuild	3.5	REDACTED
South Hall 500/230kV new auto transformer	N/A	REDACTED
STATCOMs Installation for VAR Support	N/A	REDACTED
Total	**41**	**REDACTED**

Alternate Plan 2 is not a feasible option given the following factors:

1. Accommodating and coordinating necessary outages to facilitate maintenance of existing facilities and the construction activities for system improvements
2. Timing and reduced reliability exposure to system given length of corridors
3. Lack of solution robustness to facilitate power transfers from south Georgia to north Georgia driven by increased solar generation and load growth

Additionally, the Brute Force alternative estimates do not reflect the full scope of all necessary work and costs that would be required along with any additional generation redispatch impacts associated with the numerous required outages.

Conclusion and Recommendations

Although the Preferred Plan is not the least cost plan, it was selected because it solves identified thermal constraints, provides additional 500kV corridor for generation power transfers, and provides voltage support to the area and for non-converging cases.

D. Fleet Transition Tables

This appendix provides a comparison between the transmission projects listed in the Unit Retirement Study contained within Technical Appendix Volume 2 of the 2022 Georgia Power Integrated Resource Plan (Docket 44160) and the transmission projects contained within the 2024 Georgia Integrated Transmission System Ten Year Plan (2025 – 2034). For the Unit Retirement studies, Table 33 provides a breakdown of the studied generation scenarios.

Table 33 Unit Retirement Generation Scenarios

Scenario	Generation Units	Year Unavailable
Fleet 0	Wansley 1 & 2	2022
	Bowen 1 & 2	2027
Fleet 0A	Wansley 1 & 2	2022
	Bowen 1 & 2	2027
	Scherer 3	2022
Fleet 1	Wansley 1 & 2	2022
	Bowen 1 & 2	2027
	Scherer 1 - 3	2028
Fleet 2	Wansley 1 & 2	2022
	Bowen 1 & 2	2027
	Scherer 1 - 3	2028
	Bowen 3 & 4	2028

For the 2024 Ten Year planning process, the coal generation units shown Table 34 were allowed to run throughout the planning horizon in both the version 1 and version 2 of the transmission planning load flow cases.

Table 34 Coal Generation Units

Generation Units
Bowen 1 & 2
Scherer 3
Bowen 3 & 4

Fleet Scenario 0:

Table 35 below notes the required projects from the Unit Retirement studies along with the current project number and need year of the project in the 2024 GA ITS Ten-Year Plan.

Table 35 Projects Still Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
18153	BONAIRE PRIMARY - ECHECONNEE RECONDUCTOR 115KV (BONAIRE - RUSSELL PKWY) (F.K.A. BONAIRE PRIMARY - ECHECONNEE 115KV)	2030	2025	2025	REDACTED	REDACTED	REDACTED
---	CAPITAL HEIGHTS - CARTER HILL ROAD - FISK ROAD 115KV (APC Project)	2026	2025	2025	REDACTED	REDACTED	REDACTED
18800	ECHECONNEE - WELLSTON 115KV REBUILD (S WARNER ROBINS-WELLSTON) (F.K.A. ECHECONNEE - WELLSTON 115KV)	2024	2025	2025	REDACTED	REDACTED	REDACTED
18774	GTC: HEARD COUNTY - TENASKA 500KV (NEW LINE) (F.K.A. TENASKA - HEARD CO 500KV (NEW LINE))	2024	2024	2025	REDACTED	REDACTED	REDACTED
19334	GTC: LAGRANGE - NORTH OPELIKA 230KV (NEW LINE) (F.K.A. LAGRANGE - NORTH OPELIKA 230KV (NEW LINE))	2027	2026	2026	REDACTED	REDACTED	REDACTED
18573 (F.K.A. 12016)	ARKWRIGHT - LLOYD SHOALS 115KV	2024	2024	2027	REDACTED	REDACTED	REDACTED
18671	CORN CRIB - LAGRANGE PRIMARY 115KV RECONDUCTOR (F.K.A. CORN CRIB - LAGRANGE 115KV)	2027	2024	COMPLETE	REDACTED	REDACTED	---
18104 (F.K.A. 18772)	KLONDIKE SWITCH REPLACEMENT (F.K.A. KLONDIKE - NORCROSS 500KV SWITCH REPLACEMENT)	2024	2024	COMPLETE	REDACTED	REDACTED	---

Table 36 shows the projects no longer required to implement Fleet Scenario 0 from the 2024 GA ITS Ten-Year planning process.

Table 36 Projects No Longer Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
19628	ARLINGTON PRIMARY - HWY45/234 RECONDUCTOR 115KV (F.K.A. ARLINGTON PRIMARY - DAWSON PRIMARY 115KV)	2028	2029	---	REDACTED	REDACTED	---

Fleet Scenario 0A:

Table 37 below notes the projects that required to implement Fleet Scenario 0A from the 2024 GA ITS Ten-Year planning process.

Table 37 Projects Still Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
18153	BONAIRE PRIMARY - ECHECONNEE RECONDUCTOR 115KV (BONAIRE - RUSSELL PKWY) (F.K.A. BONAIRE PRIMARY - ECHECONNEE 115KV)	2030	2025	2025	REDACTED	REDACTED	REDACTED
19187	BREMEN - CROOKED CREEK 115KV (F.K.A. BREMEN - CROOKED CREEK (APC) 115KV	2028	2025	2025	REDACTED	REDACTED	REDACTED
---	CAPITAL HEIGHTS - CARTER HILL ROAD - FISK ROAD 115KV (APC Project)	2026	2025	2025	REDACTED	REDACTED	REDACTED
18800	ECHECONNEE - WELLSTON 115KV REBUILD (S WARNER ROBINS-WELLSTON) (F.K.A. ECHECONNEE - WELLSTON 115KV)	2024	2025	2025	REDACTED	REDACTED	REDACTED
18774	GTC: HEARD COUNTY - TENASKA 500KV (NEW LINE) (F.K.A. TENASKA - HEARD CO 500KV (NEW LINE))	2024	2024	2025	REDACTED	REDACTED	REDACTED
19334	GTC: LAGRANGE - NORTH OPELIKA 230KV (NEW LINE) (F.K.A. LAGRANGE - NORTH OPELIKA 230KV (NEW LINE))	2027	2026	2026	REDACTED	REDACTED	REDACTED
19598	MEAG: DRESDEN - LAGRANGE PRIMARY 230KV UPGRADE & JUMPERS (F.K.A. MEAG: DRESDEN - LAGRANGE 230KV LINE REBUILD)	2031	2026	2026	REDACTED	REDACTED	REDACTED
12016	ARKWRIGHT - LLOYD SHOALS 115KV	2024	2024	2027	REDACTED	REDACTED	REDACTED
19950	GTC: DRESDEN - TALBOT COUNTY 500KV LINE (NEW LINE)	---	2029	2029	---	REDACTED	REDACTED
18671	CORN CRIB - LAGRANGE PRIMARY 115KV RECONDUCTOR (F.K.A. CORN CRIB - LAGRANGE 115KV)	2027	2024	COMPLETE	REDACTED	REDACTED	---
18104 (F.K.A. 18772)	KLONDIKE SWITCH REPLACEMENT (F.K.A. KLONDIKE - NORCROSS 500KV SWITCH REPLACEMENT)	2024	2024	COMPLETE	REDACTED	REDACTED	---

Table 38 shows the projects no longer required to implement Fleet Scenario 0A from the 2024 GA ITS Ten-Year planning process.

Table 38 Projects No Longer Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
19628	ARLINGTON PRIMARY - HWY45/234 RECONDUCTOR 115KV (F.K.A. ARLINGTON PRIMARY - DAWSON PRIMARY 115KV)	2028	2029	---	REDACTED	REDACTED	---

Fleet Scenario 1:

Table 39 shows the projects still required to implement Fleet Scenario 1 from the 2024 GA ITS Ten-Year planning process.

Table 39 Projects Still Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
18153	BONAIRE PRIMARY - ECHECONNEE RECONDUCTOR 115KV (BONAIRE - RUSSELL PKWY) (F.K.A. BONAIRE PRIMARY - ECHECONNEE 115KV)	2030	2025	2025	REDACTED	REDACTED	REDACTED
19187	BREMEN - CROOKED CREEK 115KV (F.K.A. BREMEN - CROOKED CREEK (APC) 115KV	2028	2025	2025	REDACTED	REDACTED	REDACTED
---	CAPITAL HEIGHTS - CARTER HILL ROAD - FISK ROAD 115KV (APC Project)	2026	2025	2025	REDACTED	REDACTED	REDACTED
18800	ECHECONNEE - WELLSTON 115KV REBUILD (S WARNER ROBINS-WELLSTON) (F.K.A. ECHECONNEE - WELLSTON 115KV)	2024	2025	2025	REDACTED	REDACTED	REDACTED
18774	GTC: HEARD COUNTY - TENASKA 500KV (NEW LINE) (F.K.A. TENASKA - HEARD CO 500KV (NEW LINE))	2024	2024	2025	REDACTED	REDACTED	REDACTED
20002	GORDON - SANDERSVILLE #1 115KV LINE REBUILD (F.K.A. GORDON - SANDERSVILLE #1 115KV)	2028	2026	2026	REDACTED	REDACTED	REDACTED
19334	GTC: LAGRANGE - NORTH OPELIKA 230KV (NEW LINE) (F.K.A. LAGRANGE - NORTH OPELIKA 230KV (NEW LINE))	2027	2026	2026	REDACTED	REDACTED	REDACTED
19999	GTC: ROBINS SPRING BUS REPLACEMENT	---	2025	2026	---	REDACTED	REDACTED
19636	HAMMOND - WEISS DAM (APC) 115KV REBUILD (F.K.A HAMMOND - WEISS DAM (APC) 115KV)	2030	2026	2026	REDACTED	REDACTED	REDACTED
19598	MEAG: DRESDEN - LAGRANGE PRIMARY 230KV UPGRADE & JUMPERS (F.K.A. MEAG: DRESDEN - LAGRANGE 230KV LINE REBUILD)	2031	2026	2026	REDACTED	REDACTED	REDACTED
12016	ARKWRIGHT - LLOYD SHOALS 115KV	2024	2024	2027	REDACTED	REDACTED	REDACTED
19950	GTC: DRESDEN - TALBOT COUNTY 500KV LINE (NEW LINE)	---	2029	2029	---	REDACTED	REDACTED
18671	CORN CRIB - LAGRANGE PRIMARY 115KV RECONDUCTOR (F.K.A. CORN CRIB - LAGRANGE 115KV)	2027	2024	COMPLETE	REDACTED	REDACTED	---
---	EUFALA - GEORGE DAM (COE) - WEBB 115KV	2030	2024	COMPLETE	REDACTED	REDACTED	---
18104 (F.K.A. 18772)	KLONDIKE SWITCH REPLACEMENT (F.K.A. KLONDIKE - NORCROSS 500KV SWITCH REPLACEMENT)	2024	2024	COMPLETE	REDACTED	REDACTED	---

Table 40 shows the projects no longer required to implement Fleet Scenario 1 from the 2024 GA ITS Ten-Year planning process.

Table 40 Projects No Longer Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
19628	ARLINGTON PRIMARY - HWY45/234 RECONDUCTOR 115KV (F.K.A. ARLINGTON PRIMARY - DAWSON PRIMARY 115KV)	2028	2029	---	**REDACTED**	**REDACTED**	---

Fleet Scenario 2:

Table 41 shows the projects still required to implement Fleet Scenario 2 from the 2024 GA ITS Ten-Year planning process.

Table 41 Projects Still Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
18153	BONAIRE PRIMARY - ECHECONNEE RECONDUCTOR 115KV (BONAIRE - RUSSELL PKWY) (F.K.A. BONAIRE PRIMARY - ECHECONNEE 115KV)	2030	2025	2025	REDACTED	REDACTED	REDACTED
19187	BREMEN - CROOKED CREEK 115KV (F.K.A. BREMEN - CROOKED CREEK (APC) 115KV	2028	2025	2025	REDACTED	REDACTED	REDACTED
---	CAPITAL HEIGHTS - CARTER HILL ROAD - FISK ROAD 115KV (APC Project)	2026	2025	2025	REDACTED	REDACTED	REDACTED
18800	ECHECONNEE - WELLSTON 115KV REBUILD (S WARNER ROBINS-WELLSTON) (F.K.A. ECHECONNEE - WELLSTON 115KV)	2024	2025	2025	REDACTED	REDACTED	REDACTED
18774	GTC: HEARD COUNTY - TENASKA 500KV (NEW LINE) (F.K.A. TENASKA - HEARD CO 500KV (NEW LINE))	2024	2024	2025	REDACTED	REDACTED	REDACTED
20002	GORDON - SANDERSVILLE #1 115KV LINE REBUILD (F.K.A. GORDON - SANDERSVILLE #1 115KV)	2028	2026	2026	REDACTED	REDACTED	REDACTED
19334	GTC: LAGRANGE - NORTH OPELIKA 230KV (NEW LINE) (F.K.A. LAGRANGE - NORTH OPELIKA 230KV (NEW LINE))	2027	2026	2026	REDACTED	REDACTED	REDACTED
19999	GTC: ROBINS SPRING BUS REPLACEMENT	---	2025	2026	---	REDACTED	REDACTED
19636	HAMMOND - WEISS DAM (APC) 115KV REBUILD (F.K.A HAMMOND - WEISS DAM (APC) 115KV)	2030	2026	2026	REDACTED	REDACTED	REDACTED
19598	MEAG: DRESDEN - LAGRANGE PRIMARY 230KV UPGRADE & JUMPERS (F.K.A. MEAG: DRESDEN - LAGRANGE 230KV LINE REBUILD)	2031	2026	2026	REDACTED	REDACTED	REDACTED
12016	ARKWRIGHT - LLOYD SHOALS 115KV	2024	2024	2027	REDACTED	REDACTED	REDACTED
19635	GTC: HICKORY LEVEL - VILLA RICA PRIMARY 230KV (Replace jumpers and reconductor) (F.K.A. HICKORY LEVEL - VILLA RICA PRIMARY 230KV)	2030	2029	2027	REDACTED	REDACTED	REDACTED
19950	GTC: DRESDEN - TALBOT COUNTY 500KV LINE (NEW LINE)	---	2029	2029	---	REDACTED	REDACTED
18671	CORN CRIB - LAGRANGE PRIMARY 115KV RECONDUCTOR (F.K.A. CORN CRIB - LAGRANGE 115KV)	2027	2024	COMPLETE	REDACTED	REDACTED	---
---	EUFALA - GEORGE DAM (COE) - WEBB 115KV (APC Project)	2030	2024	COMPLETE	REDACTED	REDACTED	---
18104 (F.K.A. 18772)	KLONDIKE SWITCH REPLACEMENT (F.K.A. KLONDIKE - NORCROSS 500KV SWITCH REPLACEMENT)	2024	2024	COMPLETE	REDACTED	REDACTED	---

Table 42 shows the projects no longer required to implement Fleet Scenario 2 from the 2024 GA ITS Ten-Year planning process.

Table 42 Projects No Longer Required

Project Number	Project Name	2021 Unit Retirement Study Need Year	2023 GA ITS TYP Need Year	2024 GA ITS TYP Need Year	2021 Planning Grade Estimate	2023 Planning Grade Estimate	2024 Planning Grade Estimate
19628	ARLINGTON PRIMARY - HWY45/234 RECONDUCTOR 115KV (F.K.A. ARLINGTON PRIMARY - DAWSON PRIMARY 115KV)	2028	2029	---	**REDACTED**	**REDACTED**	---

[D2]

ITS LOSS STUDY

2024 ITS LOSS STUDY

REPORT TO THE

TRANSMISSION PLANNING WORK GROUP

January 14, 2025

Members of ITS Loss Study Working Group

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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 2024. This study used ITS loss studies performed in 2018, 2014, 2008, 2002, 1995 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

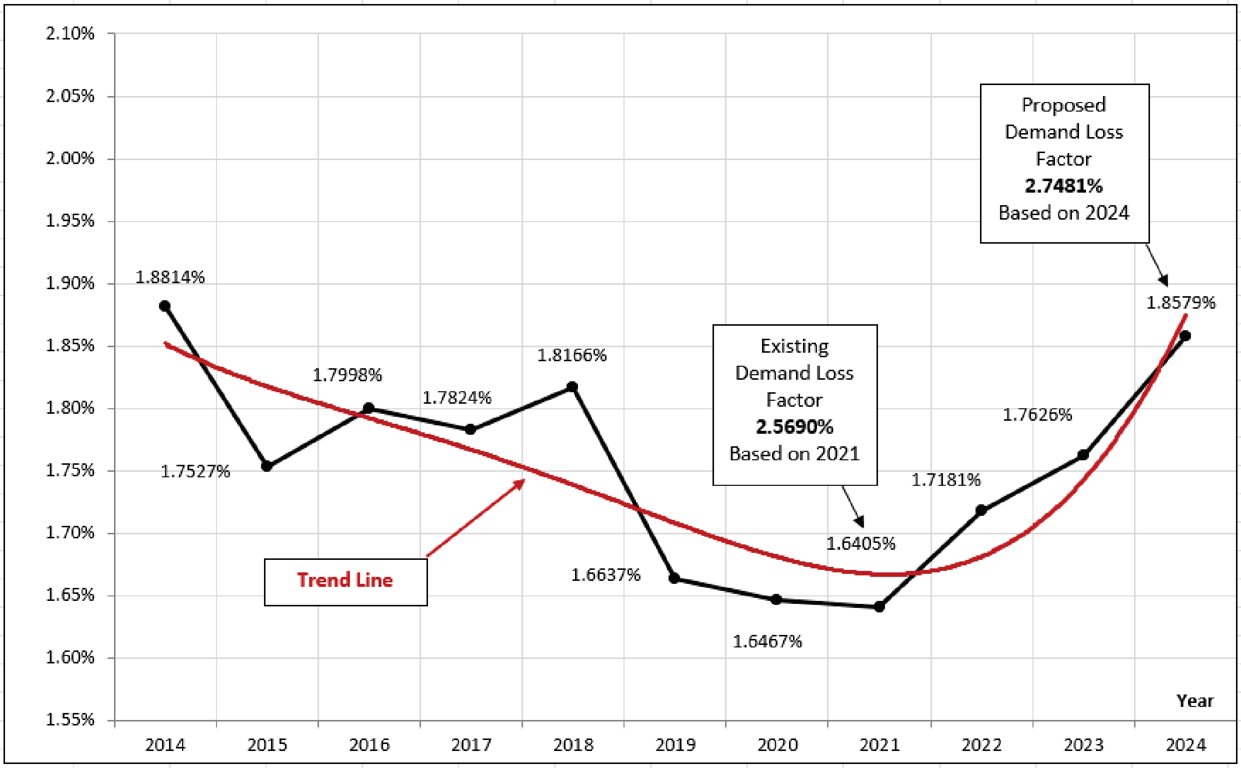
This study was conducted in two stages. The first stage consisted of modeling the transmission system (115 kV and above) as well as determining values to be used for estimating bulk transmission losses, losses in 230/xx and 115/xx transformers, losses resulting from serving station service loads, and losses on the sub-transmission 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 42 load flow cases and the average energy loss factor is based on a composite of 5904 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 contribute 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 v1Cs24 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: 2.5690% – 2022 through 2024
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 1.8579% in 2024 in the chart is the average ITS demand losses from the S24vxxs24.sav cases. The demand loss factor, e.g., 2.7481% in 2024 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 2.7481% of the total system load, while total energy loss is 3.0217% 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 sub-transmission. These losses are 2.5629% for demand and 2.7058% for energy, which account for approximately 93.2% and 89.2% of total demand and energy losses respectively, which was the expected result.

Losses due to the other components on the system, such as capacitors and reactors, catenary, contact resistances, corona, deviation from base case schedules, deviation in inadvertent interchange (loop flows), electro-magnetic fields, harmonics, insulator leakage, line out operation, overhead ground wire losses, power factor, temperature compensation resistance, unbalanced system operation and unmetered auxiliary equipment were calculated for both demand and energy by using recent data for the ITS system and applying the appropriate formulas identified in and since the 1987 study. Demand losses for these components account for 0.1852% of total load, while energy losses account for 0.3288% 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 several 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

- Recognize the attached loss factors as the most accurate available currently.
- 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.
- 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%.
- Use base cases without NSEW or SNWE transfers and account for these transfers based on input from operations.

Figure 2: Service Level Designation And Power Flow Diagram

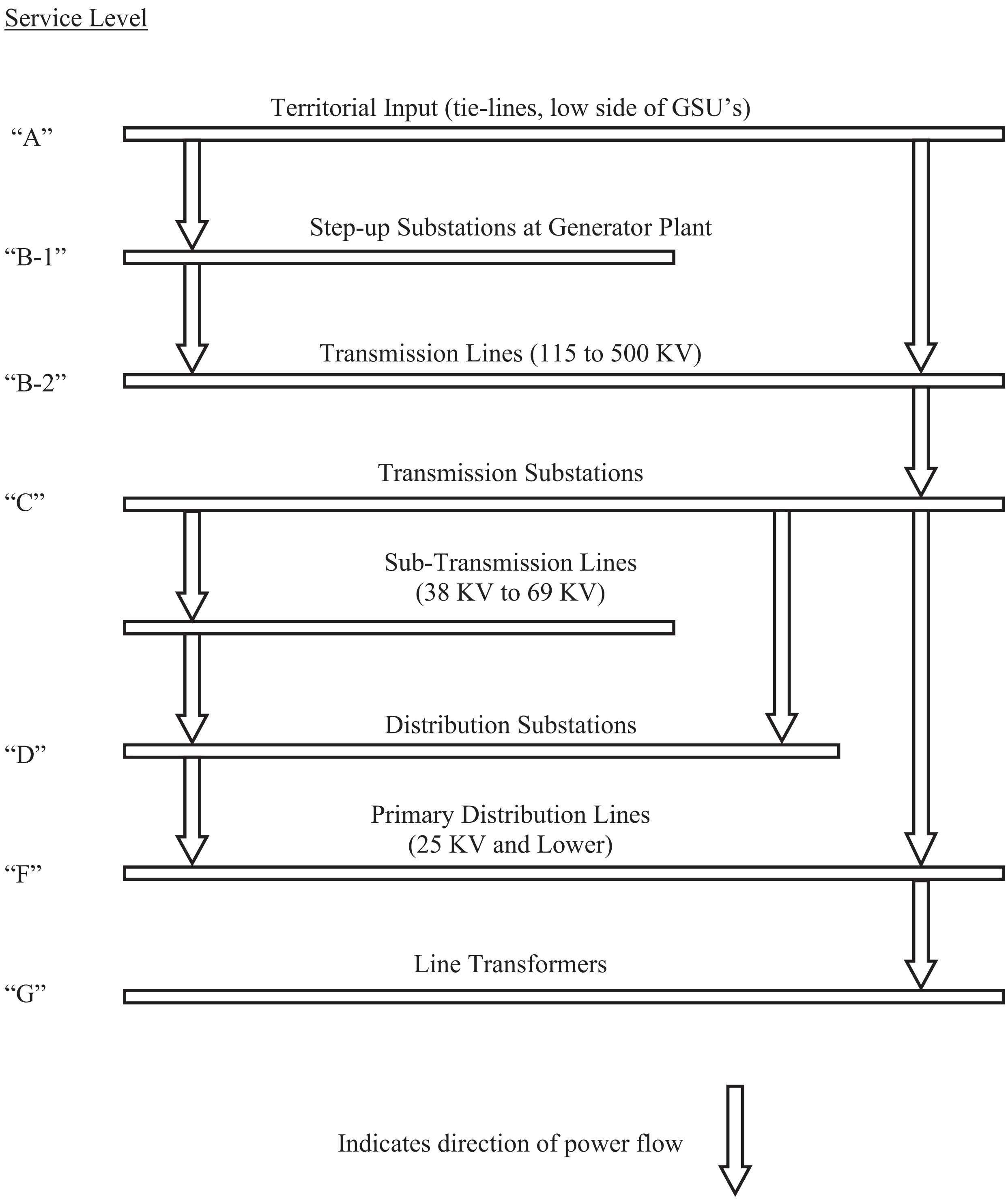


Figure 3: Service Level Designation and Power Flow Diagram

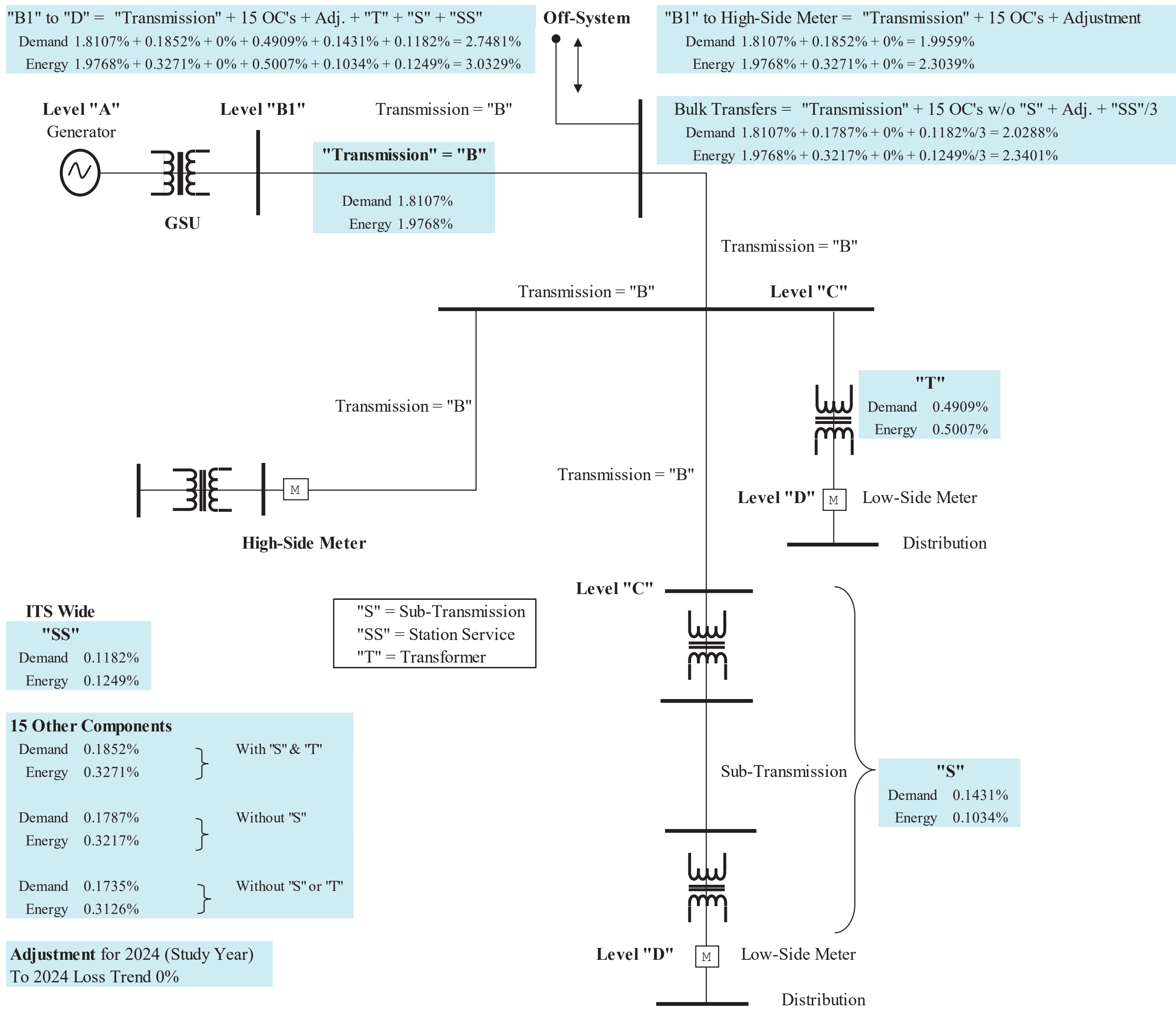


EXHIBIT 1 (2024 ITS DEMAND LOSSES)

EXHIBIT 1

2024 ITS DEMAND LOSSES

B1 TO D MAJOR COMPONENTS		2024 %	2021 %	Delta %	
Bulk Transmission	B	1.8107	1.6511	0.1596	(1)
230/xx and 115/xx Transformers	T	0.4909	0.4804	0.0105	(2)
Station Service	SS	0.1182	0.1251	-0.0069	(2)
Subtransmission (69kV and 46 kV)	S	0.1431	0.1450	-0.0019	
	Subtotal:	**2.5629**	**2.4016**	**0.1613**	

OTHER COMPONENTS		2024 %	2021 %	Delta %	
Capacitors and Reactors		0.0069	0.0071	-0.0002	
Catenary Adjustment		0.0391	0.0359	0.0032	
Contact Resistances		0.0001	0.0001	0.0000	
Corona		0.0202	0.0191	0.0011	
Deviation From Base Case Schedules		0.0000	0.0000	0.0000	
Deviation in Inadvertent Interchange		0.0297	0.0232	0.0065	
E/M Fields		0.0054	0.0050	0.0004	
Harmonics		0.0015	0.0014	0.0001	
Insulator Leakage		0.0188	0.0189	-0.0001	
Line-Out Operation Adjustment		0.0059	0.0038	0.0021	
OHGW		0.0274	0.0251	0.0023	
Power Factor Adjustment		0.0032	0.0024	0.0008	(2)
Temperature Compensation of Resistance		0.0000	0.0000	0.0000	
Unbalanced System Operation		0.0244	0.0228	0.0016	
Unmetered Auxiliary Equipment		0.0026	0.0026	0.0000	
	Subtotal:	**0.1852**	**0.1674**	**0.0178**	
Total Demand Losses		2.7481	2.5689	0.1792	
Adjustment For Trend in Base Case Losses		0.0000	0.0000	0.0000	
TOTAL TRANSMISSION DEMAND LOSSES (%)		**2.7481**	**2.5689**	**0.1792**	

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

	2024	2021	Delta	
Peak Demand =	25,852	25,879	-27	MW
Energy Use =	151,048,060	132,753,388	18,294,672	GWh
Load Factor =	66.52%	58.40%	8.12%	

PUBLIC DISCLOSURE

EXHIBIT 2 (2024 ITS ENERGY LOSSES)

EXHIBIT 2

2024 ITS ENERGY LOSSES

B1 TO D MAJOR COMPONENTS		2024 %	2021 %	Delta %	
Bulk Transmission	B	1.9768	1.4657	0.5111	(1)
230/xx and 115/xx Transformers	T	0.5007	0.4466	0.0541	(2)
Station Service	SS	0.1249	0.1249	0.0000	
Subtransmission (69kV and 46 kV)	S	0.1034	0.1106	-0.0072	(2)
	Subtotal:	**2.7058**	**2.1478**	**0.5580**	

OTHER COMPONENTS		2024 %	2021 %	Delta %	
Capacitors and Reactors		0.0038	0.0043	-0.0005	
Catenary Adjustment		0.0416	0.0315	0.0101	
Contact Resistances		0.0001	0.0001	0.0000	
Corona		0.0931	0.0845	0.0086	
Deviation From Base Case Schedules		0.0000	0.0000	0.0000	
Deviation in Inadvertent Interchange		0.0539	0.0397	0.0142	(2)
E/M Fields		0.0120	0.0137	-0.0017	
Harmonics		0.0016	0.0012	0.0004	
Insulator Leakage		0.0335	0.0323	0.0012	
Line-Out Operation Adjustment		0.0063	0.0015	0.0048	
OHGW		0.0291	0.0221	0.0070	
Power Factor Adjustment		0.0030	0.0003	0.0027	
Temperature Compensation of Resistance		0.0000	0.0000	0.0000	
Unbalanced System Operation		0.0452	0.0354	0.0098	
Unmetered Auxiliary Equipment		0.0039	0.0045	-0.0006	
	Subtotal:	**0.3271**	**0.2711**	**0.0560**	
Total Energy Losses		3.0329	2.4189	0.6140	
Adjustment For Trend in Base Case Losses		0.0000	0.0000	0.0000	
TOTAL TRANSMISSION ENERGY LOSSES (%)		**3.0329**	**2.4189**	**0.6140**	

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

	2024	2021	Delta	
Peak Demand =	25,852	25,879	-27	MW
Energy Use =	151,048,060	132,753,388	18,294,672	GWh
Load Factor =	66.52%	58.40%	8.12%	

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 sub-transmission 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 42 load flow cases and the average energy loss factor is based on a composite of 5904 load flow cases.

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 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 regarding 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 non-ITS 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 66.50 MW or 0.2418% of the ITS connected generation, which was 27,502 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 0.2418% and B1-D losses are 2.5629%, then the proper calculation for A-D losses is:

1 - ((1 - 0.002418) x (1 - 0.025629)) = 2.8046%, not 0.002418 + .025629 = 2.8108%.

The annual energy losses on GSU's were 423,457 MWh or 0.3019% of the annual ITS generation, which was 140,260,043 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 forecast with reasonable accuracy, individual substation loads, and individual generator outputs cannot be predicted with the same confidence. Fortunately, all the individual loads are distributed throughout the state and each 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 to not have a disproportionate effect of any one dispatch on transmission losses.

Load Flow Cases

This study was performed on the Southern Electric System transmission planning 2024 series, version 1C summer, winter, and Fall Peak power flow cases representing 2024 expected conditions. The peak demand loss factor is based on a composite of the no-unit-off base case and the 41 most probable single-unit and double-unit out power flow cases. The average energy loss analysis was based on a composite of the no-unit-off base case and the 40 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 5904 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 1.8107% for demand loss and 1.9768% 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 0.4909% for demand loss and 0.5007% 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 0.1182% for demand loss and 0.1298% for energy loss.

D. Sub-transmission 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 sub-transmission line loss and XX/69 and XX/46 transformers. Estimated sub-transmission 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 sub-transmission system were updated using the 2024 sub-transmission case data, based on the process and information obtained from the 2008 sub-transmission loss study done by the area planning departments. The loss values attributable to Sub-transmission Line Losses and XX/69 and XX/46 Transformer Losses are 0.1431% for demand loss and 0.1034% 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 like 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 2024, at peak, the capacitive reactive power was 5123.2 Mvar. The reactive power from shunt reactors was 408.1 Mvar.

The ITS Loss Study Working Group calculated the loss values attributable to capacitors and reactors to be 0.0069% for demand loss and 0.0038% 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 sub-transmission losses (demand and energy). This calculation results in a value of 0.0391% for demand loss and 0.0416% 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 2024 ITS transmission system miles data, the electrical losses attributable to corona are 0.0202% demand loss and 0.0931% energy loss. The impact of corona energy loss is because 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 based 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 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 loss value is 0.0297% for demand and 0.0539% for energy.

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 has 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 0.0054%. 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 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 quantity of harmonics is expected to increase. The working group calculated the value of loss attributable to harmonic distortion to be 0.0015% for demand loss and 0.0016% 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 the 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 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 0.0188% demand loss and 0.0335% 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 because 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 0.0059% for demand loss and 0.0063% 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 current induced in the OHGW loop. This magnetic coupling has 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 sub-transmission losses (demand and energy). This calculation results in a value of 0.0274% for demand loss and 0.0291% 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 2024 base case model, the ITS power factor is calculated to be 0.9695. Based on the real time data, during the peak, the power factor was calculated to be 0.9874 (slightly worse than the value represented in the model). The Power Factor Adjustment calculated by the ITS Loss Study Working Group are 0.0032% for demand loss and 0.0030% 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 unbalances 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 0.0244% for demand loss, and

- 1.75% of the sum of 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 0.0452% 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 0.0046% 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	38.19%	38.19%
2	1-Bowen	1	17.84%	56.02%
3	1-Scherer	1	6.36%	62.38%
4	1-McDonough CC	1	4.33%	66.71%
5	1-Franklin CC	1	4.33%	71.04%
6	1-Farley	1	2.94%	73.99%
7	1-Hatch	1	2.94%	76.93%
8	1-McIntosh CC	1	2.94%	79.87%
9	1-Bowen 1-Scherer	2	1.51%	81.39%
10	1-Vogtle	1	5.66%	87.04%
11	1-Bowen 1-Farley	2	0.70%	87.74%
12	1-Bowen 1-Hatch	2	0.70%	88.44%
13	1-Bowen 1-Vogtle	2	1.34%	89.78%
14	1-Hatch 1-Franklin	2	0.17%	89.95%
15	1-Bowen 1-Franklin	2	1.03%	90.98%
16	1-Scherer 1-Hatch	2	0.25%	91.23%
17	1-Scherer 1-Franklin	2	0.37%	91.60%
18	1-Hatch 1-McDonough	2	0.17%	91.77%
19	1-Bowen 1-McDonough	2	1.03%	92.79%
20	1-Franklin 1-McDonough	2	0.25%	93.04%
21	1-Hatch 1-Farley	2	0.12%	93.16%
22	1-Scherer 1-McDonough	2	0.37%	93.52%
23	1-Farley 1-Franklin	2	0.17%	93.69%
24	1-Hatch 1-Vogtle	2	0.22%	93.92%
25	1-Vogtle 1-Franklin	2	0.33%	94.24%
26	1-Scherer 1-Farley	2	0.25%	94.49%
27	1-Scherer 1-Vogtle	2	0.48%	94.97%
28	1-Farley 1-McDonough	2	0.17%	95.14%
29	1-Vogtle 1-McDonough	2	0.33%	95.47%
30	1-Hatch 1-McIntosh	2	0.12%	95.58%
31	2-Bowen	2	2.17%	97.75%
32	1-Bowen 1-McIntosh	2	0.70%	98.45%
33	1-Franklin 1-McIntosh	2	0.17%	98.62%
34	1-Vogtle 1-Farley	2	0.22%	98.84%
35	1-Scherer 1-McIntosh	2	0.25%	99.09%
36	1-McIntosh 1-McDonough	2	0.17%	99.26%
37	2-Hatch	2	0.03%	99.29%

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Rank	Units Outaged	Number of Units Out	Probability (Rounded)	Sum of Probabilities
38	2-Scherer	2	0.20%	99.49%
39	2-Franklin	2	0.09%	99.57%
40	1-Farley 1-McIntosh	2	0.12%	99.69%
41	1-Vogtle 1-McIntosh	2	0.22%	99.91%
42	2-McDonough	2	0.09%	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	29.46%	29.46%
2	1-Bowen	1	18.31%	47.77%
3	1-Scherer	1	7.46%	55.23%
4	1-McDonough CC	1	5.71%	60.94%
5	1-Franklin CC	1	5.71%	66.66%
6	1-McIntosh CC	1	3.93%	70.58%
7	1-Hatch	1	2.65%	73.23%
8	1-Farley	1	2.65%	75.88%
9	1-Bowen 1-Scherer	2	2.02%	77.90%
10	1-Bowen 1-McDonough CC	2	1.55%	79.45%
11	1-Bowen 1-Franklin CC	2	1.55%	81.00%
12	1-Vogtle	1	5.08%	86.08%
13	1-Scherer 1-McDonough CC	2	0.63%	86.71%
14	1-Scherer 1-Franklin CC	2	0.63%	87.35%
15	1-Bowen 1-McIntosh CC	2	1.07%	88.41%
16	1-Scherer 1-McIntosh CC	2	0.43%	88.84%
17	1-Bowen 1-Hatch	2	0.72%	89.56%
18	1-Bowen 1-Farley	2	0.72%	90.28%
19	1-Scherer 1-Hatch	2	0.29%	90.57%
20	1-Scherer 1-Farley	2	0.29%	90.87%
21	1-Bowen 1-Vogtle	2	1.38%	92.24%
22	1-Scherer 1-Vogtle	2	0.56%	92.81%
23	1-Hatch 1-Franklin	2	0.22%	93.03%
24	1-Franklin 1-McDonough	2	0.48%	93.51%
25	1-Hatch 1-Farley	2	0.10%	93.62%
26	1-Farley 1-Franklin	2	0.22%	93.84%
27	1-Hatch 1-Vogtle	2	0.20%	94.04%
28	1-Vogtle 1-Franklin	2	0.43%	94.47%
29	1-Farley 1-McDonough	2	0.22%	94.69%
30	1-Vogtle 1-McDonough	2	0.43%	95.12%
31	1-Hatch 1-McIntosh	2	0.15%	95.28%
32	2-Bowen	2	2.72%	97.99%
33	1-Franklin 1-McIntosh	2	0.33%	98.33%
34	1-Vogtle 1-Farley	2	0.20%	98.53%
35	1-McIntosh 1-McDonough	2	0.33%	98.86%
36	2-Hatch	2	0.03%	98.89%
37	2-Scherer	2	0.31%	99.20%
38	2-Franklin	2	0.18%	99.37%
39	1-Farley 1-McIntosh	2	0.15%	99.53%

Rank	Units Outaged	Number of Units Out	Probability (Rounded)	Sum of Probabilities
40	1-Vogtle 1-McIntosh	2	0.30%	99.82%
41	2-McDonough	2	0.18%	100.00%

Table 3. Hydro Schedule Used For 2024 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

PUBLIC DISCLOSURE

Table 4. Load Shapes Used For 2024 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	0.5962	0.5779	0.6016	0.6124	0.4977	0.4874
200	0.5796	0.5576	0.6080	0.6130	0.4943	0.4810
300	0.5769	0.5459	0.6258	0.6201	0.5033	0.4815
400	0.5948	0.5443	0.6616	0.6354	0.5323	0.4901
500	0.6300	0.5481	0.7167	0.6580	0.5816	0.5056
600	0.6468	0.5510	0.7492	0.6828	0.6061	0.5199
700	0.6443	0.5562	0.7272	0.6827	0.5901	0.5178
800	0.6581	0.5794	0.6847	0.6583	0.5683	0.5072
900	0.6926	0.6203	0.6558	0.6357	0.5607	0.5039
1000	0.7323	0.6667	0.6324	0.6136	0.5594	0.5033
1100	0.7727	0.7143	0.6128	0.5946	0.5630	0.5064
1200	0.8105	0.7543	0.5986	0.5781	0.5714	0.5116
1300	0.8384	0.7867	0.5888	0.5678	0.5796	0.5196
1400	0.8596	0.8136	0.5914	0.5706	0.5907	0.5322
1500	0.8748	0.8355	0.6186	0.5978	0.6083	0.5537
1600	0.8810	0.8496	0.6697	0.6496	0.6299	0.5832
1700	0.8806	0.8552	0.7096	0.6905	0.6519	0.6097
1800	0.8809	0.8510	0.7189	0.6994	0.6683	0.6284
1900	0.8667	0.8315	0.7134	0.6957	0.6688	0.6301
2000	0.8326	0.7982	0.6964	0.6824	0.6486	0.6125
2100	0.7764	0.7471	0.6685	0.6607	0.6107	0.5807
2200	0.7194	0.6946	0.6408	0.6379	0.5702	0.5465
2300	0.6662	0.6508	0.6205	0.6189	0.5342	0.5262
2400	0.6245	0.6078	0.6056	0.6177	0.5102	0.5014

PUBLIC DISCLOSURE

Table 5. Weighting For 2024 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	86	9,171.63	789,142	487,261	41,924,715	
Summer Week End	36	8,762.94	315,101	455,317	16,372,447	
Winter Week Day	66	6,460.15	426,370	398,399	26,294,314	
Winter Week End	25	6,019.28	150,482	381,634	9,540,838	
Fall/Spring Weekday	110	7,883.95	866,906	377,257	41,482,498	
Fall/Spring Weekend	43	7,692.83	331,112	358,565	15,433,247	
Total	366		2,879,113			
	167,092	Total Annual Energy 500/230/115 kV Transformer No-Load Losses (MWh)				
Total Annual Energy Losses	3,046,205					
Total Annual Load	151,048,060					
Energy Loss Factor (B)	**1.9768%**	LF = Loss/(Load + Loss)				

ITS JOINT SUBCOMMITTEE FOR TRANSMISSION PLANNING

2024 ITS LOSS STUDY

APPROVAL PAGE

Signed by: Will McDaniel 3E530E49C27B48E... 1/14/2025

Will McDaniel – Dalton Utilities / Date

Signed by: Jeremy Talley 40CF83E94B7A441... 1/14/2025

Jeremy Talley – Dalton Utilities / Date

Signed by: Thomas H Leslie 75D8C81E245C425... 1/14/2025

Thomas Leslie – GTC / Date

Signed by: Justin Denard 7B78F6824F4C46F... 1/14/2025

Justin Denard – GTC / Date

Signed by: Elizabeth Chase Battaglio 2E19FF5A66DF48A... 1/14/2025

Chase Battaglio – SCS / Date

Signed by: J. Chris Weaver C84E52564F4A44D... 1/14/2025

Chris Weaver – GPC / Date

Aref Moradkhani 1/15/2025

Aref Moradkhani – MEAG Power / Date

APPROVED
By Gary McAdam at 8:04 am, Jan 15, 2025

Gary McAdam – MEAG Power / Date

[E]

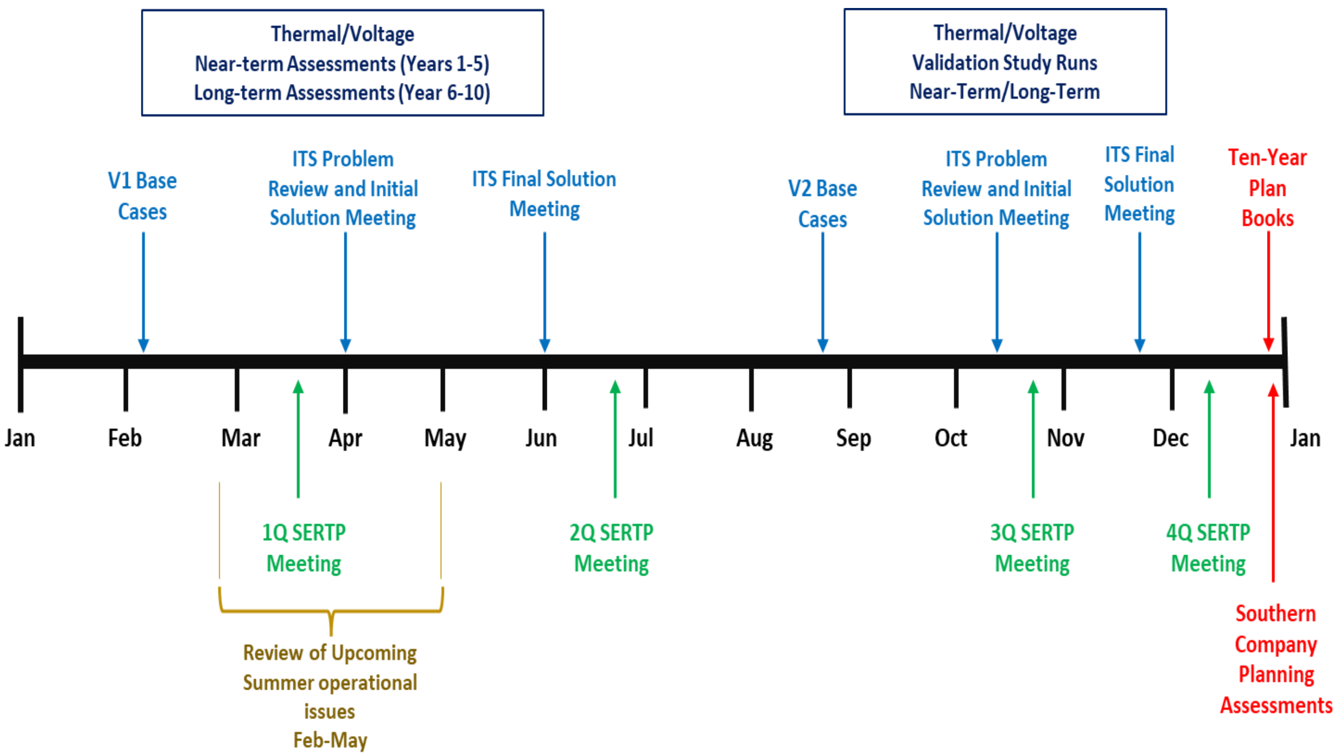
INTERFACE AND INTERCONNECTIONS

[E1]

REGIONAL TRANSMISSION PLANNING

SERTP

Southern Company participates in the Southeastern Regional Transmission Planning (SERTP) process, which is a coordinated, open and transparent process that allows for stakeholder (e.g. any interested party) feedback regarding the current ten-year transmission expansion plan. In the SERTP process, stakeholders have the opportunity to propose alternatives to projects in the latest transmission expansion plan for Southern Company to consider. The SERTP has expanded several times, both in the scope and in the size of the region, since its initial voluntary formation and now includes the following Sponsors: Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, 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 (2025-2034). Additional information on the SERTP process is available on the SERTP website at http://www.southeasternrtp.com/. The timeline below shows where the SERTP Stakeholder meetings fall during the annual planning process.



Also of note, the SERTP began implementing the additional requirements of FERC Order No. 1000 on "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities", on June 1, 2014, including:

- Participation in a regional planning process, including the development of a single, regional transmission plan
- Consideration of transmission needs driven by public policy requirements established by state, federal, or local laws or regulations, including stakeholder input regarding these types of transmission needs
- Development of qualification criteria for non-incumbent transmission developers to propose transmission projects for the purposes of regional cost allocation
- Development of a regional cost allocation methodology to allocate costs of those regional facilities selected in a regional plan for purposes of cost allocation
- Development of a common interregional cost allocation methodology to allocate costs of those interregional facilities selected in two neighboring regional plans for purposes of cost allocation

No transmission project proposals were submitted during the 2023 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 (2024-2033). Additional information on the EIPC is available on the EIPC website at http://www.eipconline.com.

[E2]

TRANSMISSION SERVICE REQUEST SUMMARY

PUBLIC DISCLOSURE

The table below lists key transmission service requests (TSRs) confirmed from 1/1/2021 through 12/13/2024 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]

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
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PUBLIC DISCLOSURE

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[redacted]											

PUBLIC DISCLOSURE

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[redacted]

PUBLIC DISCLOSURE

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PUBLIC DISCLOSURE

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PUBLIC DISCLOSURE

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[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 dictates the flow patterns involved in a bulk power transfer. Therefore, significant parallel flows (also known as “loop 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 Area (SBAA) and its neighboring balancing authority areas. From a SBAA 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 assess transfer capabilities with neighboring balancing authorities over a 10-year period. These evaluations are performed annually. 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 SBAA (Southern Companies, Georgia Transmission Corporation (GTC), or 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 December 2024.

Southern Balancing Authority Area Transfer Capability

The ability to import power from external sources is one of the many factors considered in developing a reliable and cost-effective plan for the SBAA, including GPC.

It should be emphasized that the base case used to calculate these transfer capabilities represents snapshots 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 SBAA, 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:
SOCO_ATCID_v1.7_Effective-2024-07-22.pdf (oati.com) .

Methodology for Evaluating Transfer Capability in the Planning Horizon

Transmission transfer capabilities for the SBAA 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 Working Group (LTWG) 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 SBAA 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 LTWG or Florida Interface studies, the SBAA and outside areas of the models are updated by the participating utilities. For internally performed (non – joint) evaluations, the SBAA 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 Energy Carolinas (DEC), 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 SBAA 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 SBAA and would not have significant impact on the “northern” interfaces. The Florida interface is jointly evaluated with the Florida utilities, except for Florida Power and Light Northwest Florida (“FPL-NW”) which is calculated individually 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 SBAA 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 with AC verification is used to perform transfer capability analysis on all interfaces.

Ten Year Interface Capability Plan for SBAA

Adequate transfer capability of the SBAA should be maintained to:

1. Support contractual sales and/or purchases
2. Ensure reliable operation of the system

Because the transmission providers within the SBAA 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 SBAA 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 SBAA, this import transfer capability value is established at 900 MW which is then divided between the TVA (315 MW), Duke (312MW), MISO (216 MW), and Florida (58 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/SCS_TRMID_v1.6_Effective_02-09-2024.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 SBAA and outside the SBAA.

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 SBAA 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 900 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 900 MW may not be available from a single neighboring balancing authority, CBM is reserved across several neighboring balancing authorities. The balancing authorities selected for CBM reservations 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 which consists of MISO, TVA, DEC, 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, and CBM for the applicable interfaces. Reliability margins (CBM and TRM) are not included in the cases but are considered during the analysis when determining the import capability. The import capability from Florida is evaluated jointly with the Florida utilities, with FPL-NW being calculated individually, and is discussed in the "Florida" section below.

Northern Interfaces

Import capability across all the interfaces with the SBAA is sufficient to accommodate all firm transactions and reliability margin reservations including TSAs, NLR, TRM and CBM for all years of the planning horizon.

Florida Interface

Import capability from the Florida Reliability Coordinating Council (FRCC), including FPL-NW, to SBAA is sufficient to accommodate all firm transactions and reliability margin reservations including TSAs, TRM and CBM for all years.

[E4]

OPTIMAL TRANSMISSION SITES FOR GENERATION IN GEORGIA

OPTIMAL TRANSMISSION SITING FOR GENERATION STUDY

Given that Georgia Power Company exists in a regulated market where the elimination of transmission constraints is a primary focus of transmission planning processes and 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 Transmission Siting for Generation Study is performed to identify locations where interconnected generation would not exacerbate transmission constraints.

The Optimal Transmission Siting for Generation Study follows a methodology that 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 transmission sites for generation interconnection locations, the Optimal Transmission Siting for Generation study uses the following methodology:

- A load flow model is created for the year 2029 with generation injected into a single Georgia Power owned 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 transmission site for generation interconnection.
- The list is further limited to breakered substations for ease of generator interconnection.
- A cursory review of land availability was done to identify sites located in highly populated areas with no possibility of expansion of the transmission system.

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.

Using the methodology described above, the optimal transmission siting for generation locations is at the substations listed below:

Optimal Georgia Power Transmission Substations for Generation Interconnections

Banks Crossing	Line Creek
Clermont Junction	Northwest
Cornish Mountain	Porterdale Primary
Cumming	Rockville
Dyer Road	South Hall
Glaze Drive	Winder Primary
Gravelly Creek	Yates
Jack McDonough	

[F]

GPC DISTRIBUTION SUBSTATION PROJECTS & FORECAST (FIVE-YEAR LOADING PLAN)

PUBLIC DISCLOSURE

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.

PUBLIC DISCLOSURE

PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	ADDITIONS AMOUNT
CHARLES (GPC OWNED)	Construct a 230kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment.	8/1/2024	[redacted]
HYUNDAI MOTORS	Construct a 230/25kV customer substation with two 120MVA banks, one 100MVA bank, and one 60MVA bank on customer owned property.	12/20/2024	[redacted]
SOUTHMEADOW	Construct a 230/25kV customer substation with three 60MVA banks on customer owned property. Customer paid for this facility.	12/25/2024	[redacted]
FOUR LAKES	Purchase property and construct new 115/25kV area substation. Install one 115/25kV 60MVA bank.	1/1/2025	[redacted]
TRAE LANE (GPC OWNED)	Construct a 230kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment. Customer paid for GPC owned facility.	2/28/2025	[redacted]
PUTNAM SAWMILL	Purchase property and construct a new 115/12kV area substation. Install one 115/12kV 10.5MVA bank.	3/28/2025	[redacted]
WEST DEMOREST CAPACITY INCREASE	Replace Demorest 46/12kV substation with a new West Demorest 115/12kV substation on purchased property. Install one 115/12kV 25MVA bank in the new West Demorest substation.	3/31/2025	[redacted]
INTERSTATE CENTRE BANK A CAPACITY INCREASE PROJECT	Replace 115/13.8kV 14MVA bank with a 115/25kV 60MVA bank.	4/1/2025	[redacted]
CORNELIA CAPACITY INCREASE	Remove one 115/46kV 25MVA bank and one 115/12kV 22.4MVA bank. Install two 115/12kV 40MVA banks.	6/1/2025	[redacted]
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.	6/1/2025	[redacted]
RICE HOPE	Construct 115/25kV area substation on property transferred from PHFFU. Install one 115/25kV 50MVA bank.	6/1/2025	[redacted]
SOUTHEAST STANLEY	Purchase property and construct a new 115/25kV area substation. Install one 115/25kV 40MVA bank.	6/1/2025	[redacted]
VIRGINIA AVE 3RD BANK ADDITION	Install a new 230/20kV 60MVA bank.	6/1/2025	[redacted]

PUBLIC DISCLOSURE

PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	ADDITIONS AMOUNT
BELFAST COMMERCE	Purchase property and construct new 115/25kV area substation. Install one 115/25kV 60MVA bank.	6/15/2025	[redacted]
SWITCH WAY 2ND BANK ADDITION	Install a 230/12kV 60MVA bank.	6/30/2025	[redacted]
TRANSCO BANK B CAPACITY INCREASE	Replace the 115/12kV 25MVA bank with a 115/12kV 40MVA bank.	8/1/2025	[redacted]
BULLARD ROAD	Construct a 230/34.5kV customer substation with three 150MVA banks on customer owned property.	9/1/2025	[redacted]
EUCHEE CREEK 2ND BANK ADDITION	Install a new 115/12kV 40MVA bank.	12/1/2025	[redacted]
LEWISTON	Construct 115/12kV area substation on property transferred from PHFFU. Install one 115/12kV 40MVA bank.	12/1/2025	[redacted]
PATRIOTS PARK BANK B CAPACITY INCREASE	Replace 115/12kV 25MVA Bank B with a 115/12kV 40MVA bank.	12/1/2025	[redacted]
TWO RUN RANCH	Construct a 230/25kV customer substation with two 100MVA banks, and one 60MVA bank on customer owned property.	12/31/2025	[redacted]
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.	12/31/2025	[redacted]
AVONDALE MILL ROAD BANK B CAPACITY INCREASE	Replace 115/12kV 25MVA bank B with a 115/12kV 40MVA bank.	12/31/2025	[redacted]
CASS PINE	Purchase property and construct a new 230/25kV area substation. Install one 230kV 60MVAR capacitor bank and two 230/25kV 40MVA banks.	12/31/2025	[redacted]
GODLEY TRACT 2ND BANK ADDITION	Install a new 115/13.8kV 40MVA bank.	12/31/2025	[redacted]
GREAT VALLEY	Construct new 230/25kV customer substation with three 60MVA banks on customer owned property.	12/31/2025	[redacted]
KINGSTON 2ND BANK ADDITION	Install a new 230/25kV 40MVA bank.	12/31/2025	[redacted]

PUBLIC DISCLOSURE

PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	ADDITIONS AMOUNT
MCCLAIN MOUNTAIN	Purchase property and construct a new 115/12kV area substation. Install one 115/12kV 10.5MVA bank.	12/31/2025	[redacted]
TEMPLE 2ND BANK ADDITION	Install a new 115/12kV 25MVA bank.	12/31/2025	[redacted]
BARNETT ROAD 2ND BANK ADDITION	Install a new 115/25kV 40MVA bank.	3/1/2026	[redacted]
J.C. PENNEY 2ND BANK ADDITION	Install a new 115/25kV 40MVA bank.	3/1/2026	[redacted]
PURECYCLE	Construct new 230/12kV customer substation with two 40MVA banks on customer owned property.	3/1/2026	[redacted]
BOULDER PARK	Construct new 230/25kV customer substation with four 60MVA banks on customer owned property.	3/30/2026	[redacted]
CARMEL CHURCH	Purchase property and construct a new 115/25/12kV area substation. Install one 115/25kV 25MVA bank.	3/31/2026	[redacted]
TILFORD YARDS #2	Construct a 115/25kV customer substation with two 60MVA banks on customer owned property. Customer paid for this facility	3/31/2026	[redacted]
ECHECONNEE 2ND BANK ADDITION	Install a new 115/12kV 40MVA Bank.	5/1/2026	[redacted]
BELAIR - 2ND BANK ADDITION	Install a new 115/12kV 40MVA bank.	6/1/2026	[redacted]
CLYATTVILLE CAPACITY INCREASE	Expand Clyattville substation and replace 69/12kV 5.25MVA bank with a 69/12kV 10.5MVA bank	6/1/2026	[redacted]
CREOLA (GPC OWNED)	Construct a 230kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment.	6/1/2026	[redacted]
CROOKED RIVER BANK B CAPACITY INCREASE	Replace 115/12kV 25MVA Bank B with a 115/12kV 40MVA bank.	6/1/2026	[redacted]
DAWSON FOREST CAPACITY INCREASE	Replace Dawson Forest 115/12kV substation with a new Thunder Road 115/25kV substation on purchased property. Install one 115/25kV 25MVA bank in the new Thunder Road substation.	6/1/2026	[redacted]

PUBLIC DISCLOSURE

PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	ADDITIONS AMOUNT
STONEWALL TELL ROAD (GPC OWNED)	Construct a 230kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment. Customer paid for GPC owned facility.	6/1/2026	[redacted]
SWITCH WAY 3RD BANK ADDITION	Install a 230/12kV 60MVA bank. Customer paid for this project.	6/1/2026	[redacted]
WILLIAMSON ROAD (GPC OWNED)	Construct a 115kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment. Customer paid for GPC owned facility.	6/1/2026	[redacted]
DASHER JOHNSON ROAD	Construct a 115/12kV customer substation with one 25MVA bank on customer owned property.	10/1/2026	[redacted]
CANON CAPACITY INCREASE	Replace Canon 46/12kV substation with new East Canon 115/12kV substation on purchased property. Install one 115/12kV 10.5MVA bank in the new East Canon substation.	12/31/2026	[redacted]
MANN POND	Construct a 230/25kV customer substation with four 100MVA banks on customer owned property. Customer paid for this facility.	12/31/2026	[redacted]
MEDICAL ARTS	Construct 115/13.8kV area substation on property transferred from PHFFU. Install two 115/13.8kV 25MVA banks.	12/31/2026	[redacted]
MONK ROAD CAPACITY INCREASE	Replace 115/12kV 10.5MVA bank with a 115/12kV 25MVA bank.	12/31/2026	[redacted]
NORMANDY STREET ADVANCED LAND PURCHASE	Acquire 2 acre site in the vicinity of President Street and the Boulevard - Deptford 115kV line in Savannah for future Area Substation.	12/31/2026	[redacted]
PHELPS	Purchase property and construct a new 115/12kV area substation. Install one 115/12kV 25MVA bank.	12/31/2026	[redacted]
RABBITTOWN	Purchase property and construct a new 115/25kV area substation. Install one 115/25kV 40MVA bank.	12/31/2026	[redacted]
EMBLEM RIVERSIDE	Construct a 230/25kV customer substation with two 60MVA banks. Customer paid for this facility.	3/1/2027	[redacted]
BONANZA BANK B CAPACITY INCREASE	Replace 115/25kV 40MVA bank B with a 115/25kV 60MVA bank.	6/1/2027	[redacted]
DIVIDEND ROAD BANK A CAPACITY INCREASE	Replace 115/12kV 22.4MVA Bank A with a 115/12kV 40MVA bank.	6/1/2027	[redacted]

PUBLIC DISCLOSURE

PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	ADDITIONS AMOUNT
FACTORY SHOALS ROAD CAPACITY INCREASE	Replace 115/25kV 40MVA Bank B with a 115/25kV 60MVA bank.	6/1/2027	[redacted]
SALT CREEK	Purchase property and construct a new 230/25kV area substation. Install one 230/25kV 50MVA bank.	6/1/2027	[redacted]
WINSTON	Construct a 230/34.5kV customer substation with four 150MVA banks. Customer paid for this facility	6/1/2027	[redacted]
AWS RIVER PARK BUTTS COUNTY (GPC OWNED)	Construct a 230kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment. Customer paid for GPC owned facility.	7/15/2027	[redacted]
NORTH BAGGETT	Construct a 230/34.5kV customer substation with five 150MVA transformers on customer owned property. Customer paid for this facility.	9/1/2027	[redacted]
BAKER PLACE BANK A - CAPACITY INCREASE	Replace 115/12kV 25MVA bank A with a 115/12kV 40MVA bank.	12/1/2027	[redacted]
ALLEN RD 3RD BANK ADDITION	Install a new 115/12kV, 40MVA bank.	12/31/2027	[redacted]
CENTENNIAL YARDS	Purchase property and construct a 115/20kV area substation. Install four 115/20kV 60MVA banks.	12/31/2027	[redacted]
CHICOPEE MANUFACTURING CAPACITY INCREASE	Replace Chicopee Manufacturing 115/25/12kV substation with new Balus Creek 115/25kV substation on purchased property. Install two 115/25kV 40MVA banks in the new Balus Creek substation.	12/31/2027	[redacted]
NORTH CLARKESVILLE CAPACITY INCREASE	Replace North Clarkesville 46/12kV substation with a new Historic 441 115/12kV substation on purchased property. Install one 115/12kV 10.5MVA bank in the new Historic 441 substation.	12/31/2027	[redacted]
QTS SUWANEE (GPC OWNED)	Construct a 115kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment. Customer paid for GPC owned facility.	12/31/2027	[redacted]
REST HAVEN BANK B CAPACITY INCREASE	Replace 115/25kV 10.5MVA bank with a 115/25kV 40MVA bank.	12/31/2027	[redacted]
SOCIAL CIRCLE CAPACITY INCREASE	Replace Social Circle 46/12kV substation with a new Hightower Trail 115/25kV substation on purchased property. Install two 115/25kV 40MVA banks in the new Hightower Trail substation.	12/31/2027	[redacted]

PROJECT NAME	PROJECT DESCRIPTION	NEED DATE	ADDITIONS AMOUNT
SOCIAL CIRCLE PRIMARY CAPACITY INCREASE	Remove two 46/12kV 7MVA banks, one 115/46kV 22.4MVA bank, and one 115/46kV 25MVA bank. Install one 115/25kV 40MVA bank.	12/31/2027	[redacted]
FLAT ROCK ROAD 2ND BANK ADDITION	Install a new 115/25kV 40MVA bank.	6/1/2028	[redacted]
PINE BARREN	Purchase property and construct a new 115/13.2kV area substation. Install one 115/13.2kV 40MVA bank.	10/15/2028	[redacted]
QUACCO ROAD BANK B CAPACITY INCREASE PROJECT	Replace a 115/13.2kV 33.3MVA bank with a 115/25kV 40MVA bank.	10/15/2028	[redacted]
MALLORY ROAD (GPC OWNED)	Construct a 230kV customer substation on customer owned property. Customer will install and own all the transformer banks and low-side equipment. Customer paid for GPC owned facility.	11/1/2028	[redacted]
PATRIOTS PARK BANK A CAPACITY INCREASE	Replace 115/12kV 25MVA Bank A with a 115/12kV 40MVA bank.	12/1/2028	[redacted]
AVONDALE MILL ROAD 3RD BANK ADDITION	Expand substation and install a new 115/12kV 40MVA bank.	12/31/2028	[redacted]
HIGHWAY 99 CAPACITY INCREASE	Replace 115/12kV 10MVA bank with a 115/12kV 25MVA bank.	12/31/2028	[redacted]
RUTLAND - ADVANCE LAND PURCHASE	Acquire property suitable for a future area substation on the Broadway - Echeconnee 115kV line.	12/31/2028	[redacted]

[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 2022 through 2026. This sample of 487 projects was evaluated as to cost and additional capacity added. A per kW substation cost was calculated for the group of projects. The kW used in the study was added capacity, not added load. The result of the formula below provides the Company with the Distribution Substation Average Incremental cost.

$$\$/kW = \frac{\sum \text{(Project Costs in 2024 Dollars)}}{\sum \text{(Delta kW Capacity)}}$$

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 2023 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.

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

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

Since trunk feeder and tap line planning capacity limits are proportional to the feeder voltage, a blended average of 25 kV feeder $/kW costs and lower voltage feeder $/kW costs was used.

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

Note: A power factor of .97 was used to convert kVA capacity to kW capacity.

Transmission Average Incremental Cost Methodology

The following methodology is used annually to estimate the marginal cost of transmission ($/kW) by determining the average cost to add load at existing substations utilizing the transmission planning base case models.

- Load is increased at a substation until the first transmission constraint is identified.
- A transmission project is then estimated and implemented in the case to alleviate that first constraint.
- Load is then further increased at that substation until a second transmission constraint is identified.
- The estimated cost of the transmission project is divided by the load growth afforded by the transmission project between the first and second constraints.
- This process is repeated and averaged for substations across the Southern Company footprint.

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

The method described above has historically been effective in determining the incremental transmission costs, particularly for the 115kV and 230kV systems. The Southern Balancing Authority is experiencing significant load growth that will require the need to expand the 500kV transmission system. To account for the additional investment needed for the 500kV system, a 500kV marginal cost adder has been developed,

$$500kV\ Marginal\ Cost\ Adder = \frac{Cost\ of\ 500kV\ Projects\ in\ the\ Ten\ Year\ Plan}{Y_{10}Load\ (current\ vintage) - Y_{1}Load\ (previous\ vintage)}$$

With the 500kV Marginal Cost Adder developed, the Marginal Transmission Cost becomes,

$$Marginal\ Transmission\ Cost = Average\ Incremental\ Cost + 500kV\ Marginal\ Cost\ Adder$$

[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 $5,000,000, the Finance Supervisor reviews and approves the project if acceptable.

If the project is a New Business project with costs greater than $1,000,000, the Supervisor reviews and, if acceptable, presents the project to the T&D Council for final approval.

All other 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

Transmission Blankets: Projects are created and categorized under Capital Drivers[1] (e.g. New Business, Reliability, Capital Maintenance, System Operations, Load Related System Improvements). Projects must have estimates in TEAMS and can have schedules.

[1]Through the Enterprise Foundations initiative, reporting transitioned from using Project Expenditures (PEs) to using Capital Drivers.

Distribution Blankets: Projects are created and categorized under Capital Drivers (e.g. New Business, Reliability, Capital Maintenance, Grid Improvement). The estimates and Distribution Work Orders (DWOs) 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.

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 $5,000,000 plant additions: TPRT

For New Business projects specifically, initial BCA or BCA with changes greater than $1,000,000 plant additions: TPRT, T&D Council

Initial BCA or BCA with changes greater than $5,000,000 plant additions: TPRT, T&D Council

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 $5,000,000	Transmission Project Review Team (TPRT)
Greater Than $1,000,000 - New Business Projects	TPRT, T&D Council
Greater Than $5,000,000 - All Projects	TPRT, T&D Council

Budget Change Authorizations Approvals

Project Cost	**Authorized Approval**
Less Than or Equal to $500,000	Project Manager
Greater Than $500,000 & Less Than $5,000,000	TPRT
Greater Than $1,000,000 - New Business Projects	TPRT, T&D Council
Greater Than $5,000,000 - All Projects	TPRT, T&D Council

Blanket Authorizations Approvals

Project 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 $5,000,000	TPRT
Greater Than $1,000,000 - New Business Projects	TPRT, T&D Council
Greater Than $5,000,000 - All Projects	TPRT, T&D Council

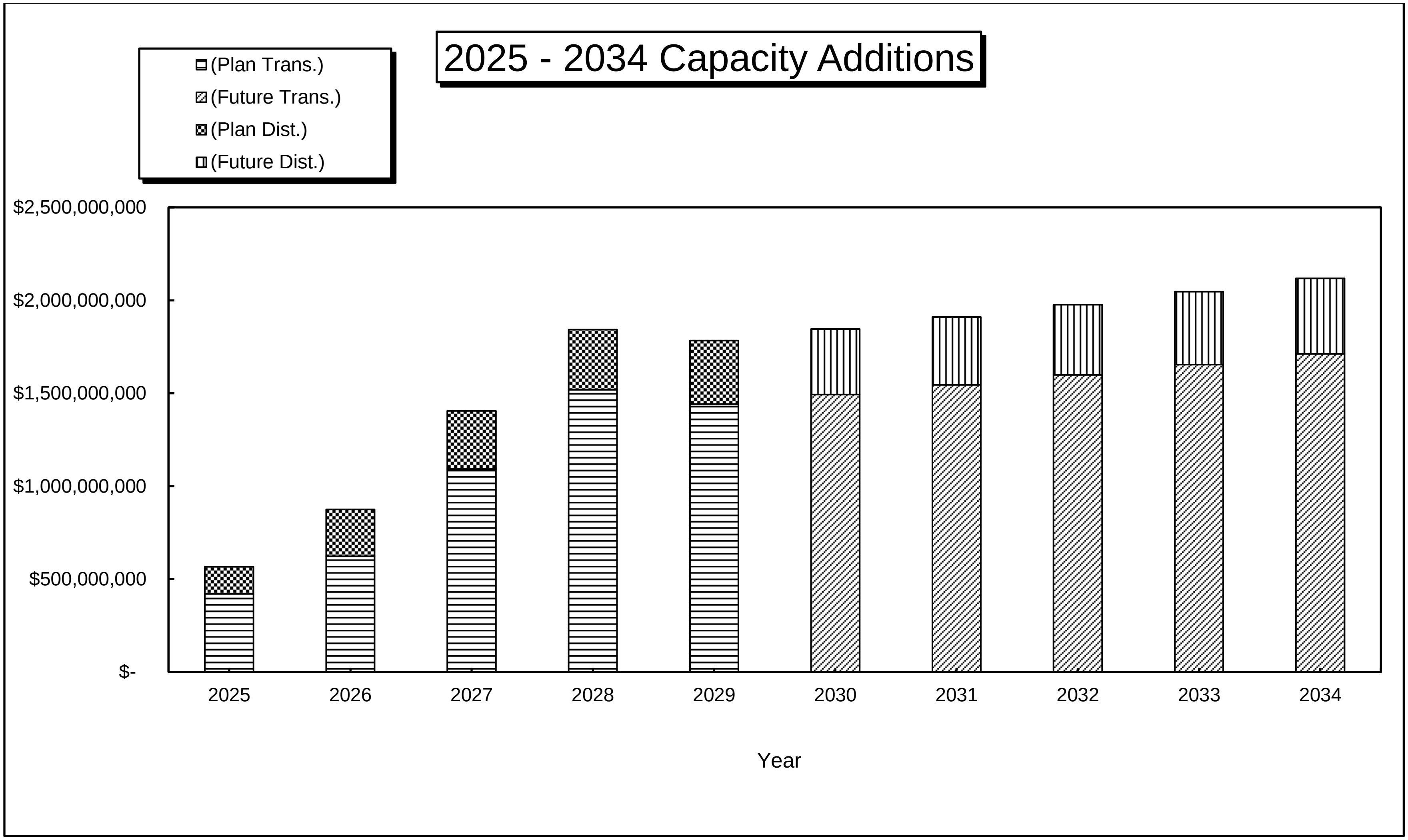
[G3]

POWER DELIVERY CAPACITY ADDITION EXPANSION PLAN

PUBLIC DISCLOSURE

2025 - 2034 T & D CAPACITY ADDITION EXPANSION PLAN

		NETWORK TRANSMISSION (Plan Trans.)	(Future Trans.)	LOAD SERVING DISTRIBUTION (Plan Dist.)	(Future Dist.)	TOTALS
1	2025	$ 419,995,051		$ 146,977,135		$ 566,972,186
2	2026	$ 623,126,504		$ 252,011,693		$ 875,138,197
3	2027	$ 1,092,359,906		$ 311,996,427		$ 1,404,356,333
4	2028	$ 1,518,597,793		$ 324,134,863		$ 1,842,732,656
5	2029	$ 1,441,978,038		$ 340,979,541		$ 1,782,957,580
6	2030		$ 1,492,447,270		$ 352,913,825	$ 1,845,361,095
7	2031		$ 1,544,682,924		$ 365,265,809	$ 1,909,948,733
8	2032		$ 1,598,746,826		$ 378,050,112	$ 1,976,796,939
9	2033		$ 1,654,702,965		$ 391,281,866	$ 2,045,984,832
10	2034		$ 1,712,617,569		$ 404,976,732	$ 2,117,594,301
	Total	**$ 5,096,057,293**	**$ 8,003,197,555**	**$ 1,376,099,659**	**$ 1,892,488,345**	**$ 16,367,842,851**


2025 - 2034 Capacity Additions
(Plan Trans.)
(Future Trans.)
(Plan Dist.)
(Future Dist.)
$2,500,000,000
$2,000,000,000
$1,500,000,000
$1,000,000,000
$500,000,000
$-
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
Year

[G4]

APPROVED PROJECTS
(BCA WITH DOCUMENTATION)

(REFER TO FOLDER "SECTION G4 – APPROVED PROJECTS" ON CEII PORTION OF GA PSC FTP SITE)

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 2022 IRP filing are included in the "Section G4 – Approved Projects" under CEII->Technical Appendix Volume 3 on the GA PSC FTP site. A sample project follows.

SOME INFORMATION IN THE SAMPLE BCA HAS BEEN REDACTED.

THE CEII FOLDER IS ONLY ACCESSIBLE TO THOSE WITH PROPER AUTHORIZATION - ALL FILES LOADED TO THE FOLDER ARE REDACTED IN THEIR ENTIRETY.

PUBLIC DISCLOSURE

POWER DELIVERY

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

Transmission Project Review Team

Project Approval Checklist

Project Information

TEAMS Project ID:	**20466**
Current Total Additions:	$[redacted]
Total Requested Additions:	$[redacted]
Increase (Decrease):	$[redacted]
CIAC:	$[redacted]
Cash Required:	$[redacted]
Removals:	$[redacted]

Project Name:

SMART VALVE INSTALLATION

Project Short Description:

Installation of Smart Valve devices in the Eatonton area to mitigate thermal constraints in multiple lines in the area.

Expedited? (No) Date: N/A

Approval Type (select one)

- ○ Conceptual Design
- ◉ New Project
- Execution Revision
  - ○ Cost Revision
  - ○ Year Revision
  - ○ Design Change
  - ○ Product Change
- ○ Order Material

ITS Treatment (Select all that apply)

- ☑ ITS Parity
- ☐ ITS Parity & DSF
- ☐ DSF only
- ☐ Non-ITS
- ☐ <$100,000
- ☐ For Information Only

Estimate Review

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

Checklist

Yes	No or N/A	
☑	☐	BCA Documents (New Projects)
☑	☐	Budget Spread by Year
☐	☑	ITS Document (WAR/PCD/TIN)
☐	☑	Land Item Required
☑	☐	Telecom and SIA Impact
☐	☑	New Business
☐	☑	Change Log
☐	☑	Distribution Scope Required
☐	☑	PD Budget Prioritization Scoring
☑	☐	Project Manager Approval in TEAMS
☐	☑	Cost Variance Explanation
☐	☑	Signed Contract (IA, Customer, DOT, WAR)

Yes	No or N/A	
☑	☐	Solution Team
☑	☐	Scoping Meeting
☑	☐	Project Plan on Project Site
☑	☐	Operations Review
☑	☐	TP East Review
☑	☐	Budget Owner Approval
☑	☐	Budget Pre Load

Compliance Impact

Yes	No or N/A	
☐	☑	Security
☑	☐	PRC 6/1/2025
☐	☑	Vegetation
☐	☑	Other

Project Contacts

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

Date: 3/11/2024 Distribution Project Manager: N/A

Project ID: **20466**

Originator: [redacted] Department: TRANSMISSION PLANNING - EAST

Project Manager: [redacted]

Project Name: **SMART VALVE INSTALLATION**
Project Need Date: 06/01/2025
Estimated Start Date:
Latest Required Date: 06/01/2025 **This Revision:** [redacted]
Funding Numn: **11073072**

Category: 20466 Smart Valve Installation Type: Capital
Region: CENTRAL
Area: CENTRAL-ATHENS, CENTRAL-MACON

Approvals and Dates:

Project Manager	[redacted]	Lead Project Manager	
Financial Supervisor		Budget Coordinator	

Project Description:

BCA Approved 11/15/23
Installation of Smart Valve devices in the Eatonton and Branch areas to mitigate thermal constraints in several lines in the area.

Supporting Statement: [redacted]

Project Item No.	Facility Name / Fac Reqd / Area Location / Project Description	Ownr	Engr.	Plt Addn Loc
	EATONTON PRIMARY			**$**[redacted]
2046601	06/01/2025	GPCO		15-542

OPTION 1: Installing Smart Valve Just Outside the existing fence - Northwest side see attachment to this PI.
Installation of Smart Valve devices at Eatonton Primary on the Eatonton Primary-Oasis 230kV line and the Branch - Oasis 230kV line.

This PI covers (intends to capture) Smart Valve material and GPC construction labor only.

All other costs will be captured on PI 2046607.

Project ID: **20466**

Project Item No.	Facility Name / Fac Reqd / Area Location / Project Description	Ownr	Plt Engr.	Addn Loc
	EATONTON PRIMARY - OASIS 230KV		**$**[redacted]	
2046604	06/01/2025	GPCO		

GPC LINE WORK:

Line modifications to first outside the northwest side of substation: Between substation structure and structrue 42.

1/22/2024 ROF Note: Estimate most conservative scenario to be able to cover the highest potential cost associate with this work.

Summary of Scope of Work:
Line modifications to first outside the northwest side of substation: Between substation structure and structure 42.
Segment: SW 190231 EATONTON (42) - STR (89)
Structure 42: (2) Lattice Steel 100 feet high; Martin 1361.5 54/19 ASCR Conductor
- (3) Brown Disc Insulators 16 Disc per String; (12) Steel Galvanized 7/16" Guys, (12) 2 Helix Anchors; Grounding # 2CU

*** Estimators comments are located in the "Estimate Notes" tab ***

****************PCA NOTES - [redacted] 02/13/2024****************

- Update Eatonton Primary-Oasis 230kV TLD as necessary.

***************END PCA NOTES*****************

	BRANCH - OASIS 230KV		**$**[redacted]	
2046605	06/01/2025	GPCO		

GPC LINE WORK:

Line modifications to first outside the northwest side of substation: Between substation structure and structrue 42.

1/22/2024 ROF Note: Estimate most conservative scenario to be able to cover the highest potential cost associate with this work.

Summary of Scope of Work:
Line modifications to first outside the northwest side of substation: Between substation structure and structure 42.
Segment: SW 190319 EATONTON PRIMARY (42) - STR 89
Structure 42: (2) Lattice Steel 100 feet high; Martin 1361.5 54/19 ASCR Conductor
- (3) Brown Disc Insulators 16 Disc per String; (12) Steel Galvanized 7/16" Guys, (12) 2 Helix Anchors; Grounding # 2CU

*** Estimators comments are located in the "Estimate Notes" tab.***

****************PCA NOTES - [redacted] 02/13/2024****************

- Update Branch-Oasis 230kV line TLD as necessary.

***************END PCA NOTES*****************

Project Item No.	Facility Name / Fac Reqd / Area Location / Project Description	Ownr	Plt Engr.	Addn Loc
	EATONTON PRIMARY 190442 - RAYONIER 46 KV		$[redacted]	
2046606	06/01/2025	GPCO		

GPC LINE WORK: Needed for Option 1.

Line modifications between structures 1A,1 and 2 to acommodate the installation of Smart Valve on the 230kV lines just outside the Eatonton Primary station.

1/22/2024 ROF Note: Estimate most conservative scenario to be able to cover the highest potential cost associate with this work.

Summary of Scope of Work:
Line modifications between structures 1A and 2 to accommodate the installation of Smart Valve on the 230kV lines just outside the Eatonton Primary station.

Segment 3: SW 190319 EATONTON PRIMARY (42) - STR 89; Penguin 4/0 ACSR w/ 6/1 Stranding; 5/16" Galvanized Steel Shield Wire
- Structure 2: 65'/Class H1S Concrete Pole; (3) 69kV Polymer Post Insulators & (5) 20K. 10" Porcelain Disc w/ 7 Disc per String Insulators; 7#10 CW Driven Rod Grounding; (6) ½" Galvanized Steel w/ 7 Stranding Guy Wires; (4) 2 Helix Anchors; (6) Fiberglass w/ 54 Length and 50000 Strength Guy Insulators.

Segment 2: EATONTON JCT (1) - SW 190401 N.O. EATONTON; Linnet 336.4 w/ 26/7 Stranding ACSR; 5/16" Galvanized Steel Shield Wire
- Structure 2: 40'/Class 4 Wood Pole; (6) Brown Disc Insulators w/ 5 disc per string; 7#10 CW Driven Rod Grounding; (3) 3/8" Galvanized Steel Guy Wires w. 7 Stranding; (3) Expanding Guy Anchors; (1) Fiberglass ACME Guy Insulator w/ 35 Length and 21000 Strength; (2) Fiberglass ACME Guy Insulator w/ 54 Length and 21000 Strength

Segment 1: SW 190443 EATONTON - EATONTON JCT; Linnet 336.4 w/ 26/7 Stranding ACSR; 5/16" Galvanized Steel Shield Wire
- Structure 1: 60'/Class 2 Wood Pole; (2) 7/16" Galvanized Steel Guys; (2) Single Helix Anchors; (2) Fiberglass ACME Electric 54 Length w/ 21000 Strength Guy Insulators;
- Structure 1A: 45'/Class 3 Wood Pole (6) Polymer 46kV Strain w/ 1 disc per string & (3) Polymer Post 46kV w/ disc per string; 2) 7/16" Galvanized Steel Guys; (1) 2 Helix Anchors; (2) Fiberglass ACME Electric 54 Length w/ 21000 Strength Guy Insulators;

Estimate Assumptions:
Remove
- 720' Transmission Conductors and OHGW
- Structure 1A, 1, 2, & 2
Install
- 720' transmission conductors and OHGW
- Structure 2 Segment 3: 45'/LC7 Concrete Pole; 3-Way Deadend; (3WECB3; BT-.038.1)
- Structure 2A: 45'/LC7 Concrete Pole; One Pole Double String, Type 3 Large Angle Structure (1CDS3; BT-020.1)
- Structure 1: 45'/LC7 Concrete Pole; One Pole Double String, Type 2 Medium Angle Structure (1SCSP2; BT-018.1)
- Structure 1A: 45'/LC7 Concrete Pole; One Pole Double String, Type 2 Medium Angle Structure (1SCSP2; BT-018.1)
- Structure 2 Segment 2: 40/LC7 Concrete Pole; One Pole Double String, Type 2 Medium Angle Structure (1SCSP2; BT-018.1)

Labor Estimates
Engineering
- Pre-Engineering - [redacted] Hours
- Preliminary Engineering -[redacted] Hours

- Field Activity - Engineering -[redacted] Hours
- Eng/Design - [redacted] Hours
Construction
- Labor - [redacted] weeks @ [redacted] days per week ([redacted] on 2/8/24)
Construction Support
- ROW Clearing - N/A
- Crew Support - 10 units @ $[redacted] = $[redacted] Total
? [redacted] weeks @ $[redacted] per Week
- Civil - Final pole locations, classes, and work sequences to be coordinated with civil site plan and final grade for smart valve installation.

EATONTON PRIMARY **$**[redacted]

2046607 06/01/2025 GPCO 15-542

OPTION 1: Installing Smart Valve Just Outside the existing fence - Northwest side see attachment to this PI.
Installation of Smart Valve devices at Eatonton Primary on the Eatonton Primary-Oasis 230kV line and the Branch - Oasis 230kV line.

This PI covers (intends to capture) SoCo/GPC efforts related to the project. Smart Valve material and labor has been captured on PI 2046601.

Additional Scope (1/31/24): Install traps and tuners on either side of the Smart Valves devices for both 230kV lines.

****************PCA NOTES - [redacted]02/13/2024****************

Oasis 230kV Line:
- Update relay settings for new Smart Valve. Increase Zone 2 to cover entire line impedance with full Smart Valve impedance.

***************END PCA NOTES*****************

Project ID: **20466**

Items

Proj Item :	2046601	2046604	2046605	2046606	2046607
Plt Add :	[redacted]				
(CIAC) :		[redacted]			
Net Add :	[redacted]				
(Plt Tfr):		[redacted]			
Removal :		[redacted]			
(CIRC) :		[redacted]			
(Salvage):		[redacted]			
Cash Rqd :	[redacted]				
OCR :		[redacted]			

Funding :	11073072
Proj Item :	Totals
Plt Add :	[redacted]
(CIAC) :	[redacted]
Net Add :	[redacted]
(Plt Tfr):	[redacted]
Removal :	[redacted]
(CIRC) :	[redacted]
(Salvage):	[redacted]
Cash Rqd :	[redacted]
OCR :	[redacted]

** End of Report **

PUBLIC DISCLOSURE

Budget Spread Request

TEAMS ID:	20466
Current Total Additions:	$ [redacted]
Total Requested Additions:	$ [redacted]
Increase (Decrease):	$ [redacted]
CIAC:	$ [redacted]
Cash Required:	$ [redacted]
Removals:	$ [redacted]

Project Information

Project Name:

SMART VALVE INSTALLATION

Budget Spread Requirements

Each Project Item requires an individual Budget Spread. All dollars should be Cash Required. Each PI total should match Estimated Cost By Units Report. For Revisions, only add new Project Items, canceled Project Items or out of variance Project Items.

Project Item	2046601						
OP Task	**Total Amount**	**Previous**	**2024**	**2025**	**2026**	**2027**	**Total**
Task 10 - Engineering							
Labor							$ -
Overheads							$ -
Transportation		$ -					$ -
Task 12 - Land							
Labor		$ -					$ -
Material		$ -					$ -
Overheads		$ -					$ -
Transportation		$ -					$ -
Task 14 - Material							
Material	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]			$ [redacted]
Task 15 - Construction							
Labor	$ [redacted]	$ -		$ [redacted]			$ [redacted]
Overheads		$ -					$ -
Transportation		$ -					$ -
Task Z - Other Project Offsets							
Task 92 - CIAC		$ -					$ -
Task 94 - Salvage		$ -					$ -
Task 98 - AFUDC		$ [redacted]					$ [redacted]
Requested Cash Req'd	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]

*Raw Cost totals for each OP task can be found using TEAMS to OP POWER BI report

PUBLIC DISCLOSURE

Budget Spread Request

Project Information

Project Name:

SMART VALVE INSTALLATION

Budget Spread Requirements

Each Project Item requires an individual Budget Spread. All dollars should be Cash Required. Each PI total should match Estimated Cost By Units Report. For Revisions, only add new Project Items, canceled Project Items or out of variance Project Items.

TEAMS ID:	**20466**
Current Total Additions:	$[redacted]
Total Requested Additions:	$[redacted]
Increase (Decrease):	$[redacted]
CIAC:	$[redacted]
Cash Required:	$[redacted]
Removals:	$[redacted]

Project Item	**2046604**						
OP Task	**Total Amount**	**Previous**	**2024**	**2025**	**2026**	**2027**	**Total**
Task 10 - Engineering							
Labor	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]
Overheads	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]
Transportation	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]
Task 12 - Land							
Labor		$ -	$ -	$ -	$ -	$ -	$ -
Material		$ -	$ -	$ -	$ -	$ -	$ -
Overheads		$ -	$ -	$ -	$ -	$ -	$ -
Transportation		$ -	$ -	$ -	$ -	$ -	$ -
Task 14 - Material							
Material	$ [redacted]	$ -	$ -	$ [redacted]	$ -	$ -	$ [redacted]
Task 15 - Construction							
Labor	$ [redacted]	$ -	$ -	$ [redacted]	$ -	$ -	$ [redacted]
Overheads	$ [redacted]	$ -	$ -	$ [redacted]	$ -	$ -	$ [redacted]
Transportation	$ [redacted]	$ -	$ -	$ [redacted]	$ -	$ -	$ [redacted]
Task Z - Other Project Offsets							
Task 92 - CIAC		$ -	$ -	$ -	$ -	$ -	$ -
Task 94 - Salvage		$ -	$ -	$ -	$ -	$ -	$ -
Task 98 - AFUDC	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]
Requested Cash Req'd	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]

*Raw Cost totals for each OP task can be found using TEAMS to OP POWER BI report

PUBLIC DISCLOSURE

Budget Spread Request

Project Information

Project Name:

SMART VALVE INSTALLATION

Budget Spread Requirements

Each Project Item requires an individual Budget Spread. All dollars should be Cash Required. Each PI total should match Estimated Cost By Units Report. For Revisions, only add new Project Items, canceled Project Items or out of variance Project Items.

TEAMS ID:	**20466**
Current Total Additions:	$[redacted]
Total Requested Additions:	$[redacted]
Increase (Decrease):	$[redacted]
CIAC:	$[redacted]
Cash Required:	$[redacted]
Removals:	$[redacted]

Project Item	**2046605**						
OP Task	**Total Amount**	**Previous**	**2024**	**2025**	**2026**	**2027**	**Total**
Task 10 - Engineering							
Labor	$ [redacted]		$ [redacted]	$ [redacted]			$ [redacted]
Overheads	$ [redacted]		$ [redacted]	$ [redacted]			$ [redacted]
Transportation	$ [redacted]		$ [redacted]	$ [redacted]			$ [redacted]
Task 12 - Land							
Labor							$ -
Material							$ -
Overheads							$ -
Transportation							$ -
Task 14 - Material							
Material	$ [redacted]			$ [redacted]			$ [redacted]
Task 15 - Construction							
Labor	$ [redacted]			$ [redacted]			$ [redacted]
Overheads	$ [redacted]			$ [redacted]			$ [redacted]
Transportation	$ [redacted]			$ [redacted]			$ [redacted]
Task Z - Other Project Offsets							
Task 92 - CIAC							$ -
Task 94 - Salvage							$ -
Task 98 - AFUDC	$ [redacted]		$ [redacted]	$ [redacted]			$ [redacted]
Requested Cash Req'd	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]

*Raw Cost totals for each OP task can be found using TEAMS to OP POWER BI report

PUBLIC DISCLOSURE

Budget Spread Request

Project Information

Project Name:

SMART VALVE INSTALLATION

Budget Spread Requirements

Each Project Item requires an individual Budget Spread. All dollars should be Cash Required. Each PI total should match Estimated Cost By Units Report. For Revisions, only add new Project Items, canceled Project Items or out of variance Project Items.

TEAMS ID:	**20466**
Current Total Additions:	$ [redacted]
Total Requested Additions:	$ [redacted]
Increase (Decrease):	$ [redacted]
CIAC:	$ [redacted]
Cash Required:	$ [redacted]
Removals:	$ [redacted]

Project Item	**2046606**						
OP Task	**Total Amount**	**Previous**	**2024**	**2025**	**2026**	**2027**	**Total**
Task 10 - Engineering							
Labor	$ [redacted]		$ [redacted]				$ [redacted]
Overheads	$ [redacted]		$ [redacted]				$ [redacted]
Transportation	$ [redacted]		$ [redacted]				$ [redacted]
Task 12 - Land							
Labor			$ -				$ -
Material			$ -				$ -
Overheads			$ -				$ -
Transportation			$ -				$ -
Task 14 - Material							
Material	$ [redacted]		$ [redacted]				$ [redacted]
Task 15 - Construction							
Labor	$ [redacted]		$ [redacted]				$ [redacted]
Overheads	$ [redacted]		$ [redacted]				$ [redacted]
Transportation	$ [redacted]		$ [redacted]				$ [redacted]
Task Z - Other Project Offsets							
Task 92 - CIAC			$ -				$ -
Task 94 - Salvage			$ -				$ -
Task 98 - AFUDC	$ [redacted]		$ [redacted]				$ [redacted]
Requested Cash Req'd	$ [redacted]	$ -	$ [redacted]	$ -	$ -	$ -	$ [redacted]

*Raw Cost totals for each OP task can be found using TEAMS to OP POWER BI report

PUBLIC DISCLOSURE

Budget Spread Request

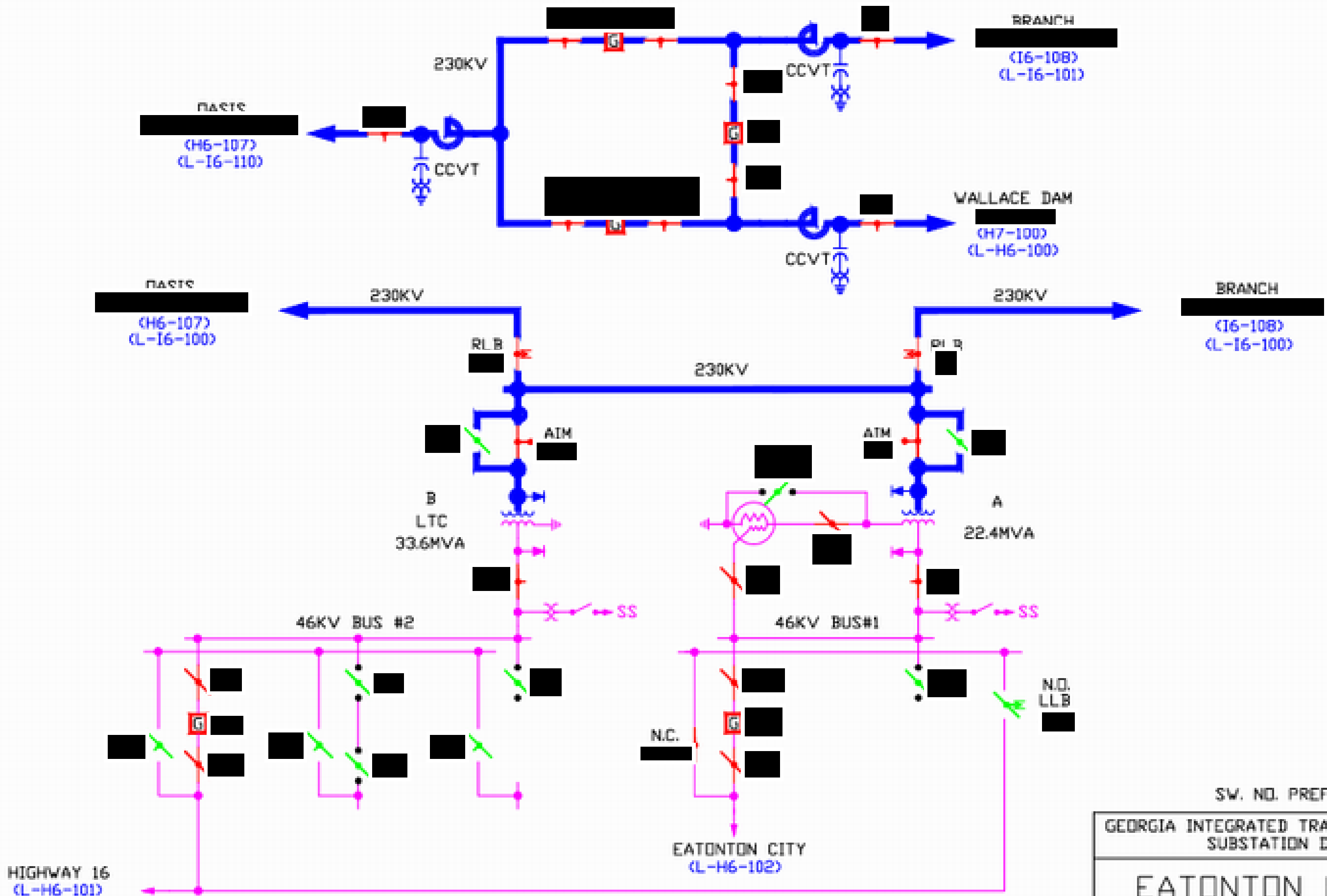
Project Information	
Project Name:	
SMART VALVE INSTALLATION	
Budget Spread Requirements	
Each Project Item requires an individual Budget Spread. All dollars should be Cash Required. Each PI total should match Estimated Cost By Units Report. For Revisions, only add new Project Items, canceled Project Items or out of variance Project Items.	

TEAMS ID:	**20466**
Current Total Additions:	$[redacted]
Total Requested Additions:	$[redacted]
Increase (Decrease):	$[redacted]
CIAC:	$[redacted]
Cash Required:	$[redacted]
Removals:	$[redacted]

Project Item	**2046607**						
OP Task	**Total Amount**	**Previous**	**2024**	**2025**	**2026**	**2027**	**Total**
Task 10 - Engineering							
Labor	$ [redacted]		$ [redacted]	$ [redacted]			$ [redacted]
Overheads	$ [redacted]		$ [redacted]	$ [redacted]			$ [redacted]
Transportation	$ [redacted]	$ -	$ [redacted]	$ [redacted]			$ [redacted]
Task 12 - Land							
Labor		$ -					$ -
Material		$ -					$ -
Overheads		$ -					$ -
Transportation		$ -					$ -
Task 14 - Material							
Material	$ [redacted]			$ [redacted]			$ [redacted]
Task 15 - Construction							
Labor	$ [redacted]			$ [redacted]			$ [redacted]
Overheads	$ [redacted]			$ [redacted]			$ [redacted]
Transportation	$ [redacted]			$ [redacted]			$ [redacted]
Task Z - Other Project Offsets							
Task 92 - CIAC							$ -
Task 94 - Salvage							$ -
Task 98 - AFUDC	$ [redacted]			$ [redacted]			$ [redacted]
Requested Cash Req'd	$ [redacted]	$ -	$ [redacted]	$ [redacted]	$ -	$ -	$ [redacted]

*Raw Cost totals for each OP task can be found using TEAMS to OP POWER BI report

PUBLIC DISCLOSURE



SW. NO. PREFIX 190

GEORGIA INTEGRATED TRANSMISSION SYSTEM
SUBSTATION DIAGRAM

EATONTON PRIMARY

Drawn: 01-10-00 | Revised: 04-20-21 CJM

SHEET NO. H6-103

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:22:59 PM

Project Item:	2046601	Job ID:	2046601
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	5/30/2025 (Scheduled) Facility Required Date: 6/1/2025		
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	EATONTON PRIMARY SUB	[redacted]	A	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
											HPB01	PR_SS	0
G1-GATE1	GATE 1 INITIATION PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
G1-GATE12	SUBMIT GATE 1 TRANSITION (1-20)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE1	PR_FF	0
											G1-PRIOR	PR_FS	0
G1-PRIOR	VALIDATE PROJECT PRIORITIZATION (1-18)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
G1-SCHEDULE	INITIATE LONG RANGE PLANNING SCHEDULE (1-15)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
DEREST	DISTRIBUTION CONCEPTUAL ESTIMATE REQUEST (NOT NEEDED)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DPRTCA	PR_FS	0
DEREST01	DISTRIBUTION CONCEPTUAL DESIGN ENGINEERING	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST	PR_FS	0
DEREST02	DISTRIBUTION CONCEPTUAL ESTIMATE SUBMITTAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST01	PR_FS	0
DISTCC	DISTRIBUTION CONSTRUCTION COMPLETION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTOHC	PR_FS	0
											DISTUDC	PR_FS	0
DISTEASE	DISTRIBUTION EASEMENT	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTJPS	DISTRIBUTION JOB PACKAGE SUBMITTAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTEASE	PR_FS	0
											DISTPERM	PR_FS	0
											DPRTFAP	PR_FS	0
DISTMAT	DISTRIBUTION ORDER LONG LEAD MATERIAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTOHC	DISTRIBUTION OVERHEAD CONSTRUCTION (NOT NEEDED)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTPERM	DISTRIBUTION PERMITTING	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTUDC	DISTRIBUTION UNDERGROUND CONSTRUCTION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTWOC	DISTRIBUTION FIELD CLOSE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTCC	PR_FS	40
DPRTCA	DPRT CONCEPT APPROVAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
											G2-CEDESMET	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:22:59 PM

Project Item: 2046601
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

DPRTFAP	DPRT/ BEST PRACTICE FINAL APPROVAL FOR DISTRIBUTION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
G2-ALL03	CONCEPTUAL/FORMAL SITE LOCATION (NOT NEEDED)	[redacted]	A	[redacted]	A	RAWE	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDCE01	PR_FS	3
G2-SCOPEPHASE	PROJECT SCOPING PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-STAKE	PR_FS	0
G2-CEDESMET	CONCEPTUAL DESIGN KICKOFF MEETING	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-PEGWO	PR_FS	2
G2-RISKMAN	UPDATE RISK MANAGEMENT PLAN	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-GTSRVW	PR_FS	0
											G2-PREOUTAGE	PR_FS	0
G2-STAKE	STAKEHOLDER NOTIFICATION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE12	PR_FS	10
HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-WOSUS	PR_FS	0
G2-CONCEP	GATE 2 CONCEPTUAL DESIGN PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_SS	0
G2-HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-SCOPEPHASE	PR_SS	0
G2-DEDCE01	PRELIMINARY CONCEPTUAL DESIGN PLAN DWG	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	3
G2-PREOUTAGE	PRELIMINARY OUTAGE COORDINATION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-DEDQAEST	PR_FS	2
											G2-DEDSFED	PR_FS	2
											G2-GTSRVW	PR_FS	2
G2-PEGWO	CREATE WORK ORDER	[redacted]	A	[redacted]	A	HLUN	SUBA	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_FS	3
G2-WOSUS	WORK ORDER SUSPENSION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DESC	PR_FF	0
											G2-ALS013	PR_FS	0
											G2-BAS01	PR_FS	0
											G2-CONCEP	PR_FF	0
											G2-RISKMAN	PR_FS	0
G2-BAS01	SEND & ASSIGN GATE 3 PRELIMINARY BASELINE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-RISKMAN	PR_SS	0
G2-ALS013	SITE EVALUATION	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL03	PR_SS	0
G2-PGAT	PRELIMINARY GEOTECH ASSESSMENT	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-ALL03	PR_FS	2
											G2-DEDCE01	PR_FS	2
G2-SCOPE	SCOPING MEETING	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL03	PR_FS	2

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
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Project Item: 2046601
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											G2-CEDESMET	PR_FS	0
											G2-DEDCE01	PR_FS	2
G2-DEDCE02	CONCEPTUAL DESIGN PLAN DWG	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDCE01	PR_FS	0
											G2-SCOPE	PR_FS	2
G2-EECRL01	CONCEPTUAL PCA SHORT CIRCUIT STUDY	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	2
											G2-SCOPE	PR_FS	2
ALS01	PROPERTY OWNER NOTIFICATION (NOT NEEDED)	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	0
EQPT	MATERIALS LOE	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	DEDRQN	PR_SS	0
											PEGWO	PR_SS	0
G3-GATE3	GATE 3 ENGINEERING PHASE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_SS	0
PEGWO	WORK ORDER (CREATE / UNSUSPEND)	[redacted]	S	[redacted]	S	HLUN	SUBA	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	5
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	0
G2-CESTRFDN	CONCEPTUAL CIVIL FOUNDATION REVIEW	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-DEDCE02	PR_SS	0
											G2-PGAT	PR_FS	2
G2-CEOILCON	PRELIMINARY OIL CONTAINMENT ASSESSMENT	[redacted]	A	[redacted]	A	DRTH	CASH	[redacted]	[redacted]	[redacted]	G2-CESTRFDN	PR_SS	2
G2-EECRL02	CONCEPTUAL PCA RELAY STUDY	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECRL01	PR_FS	0
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	KKOS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
DED01	PHYSICAL ENGINEERING	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
DEDRQN	REQUISITION PHYSICAL NON-STOCK MATERIAL	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED01	PR_SS	0
EECSK	PROTECTION & CONTROL PACKAGE	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	DMRI	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	5
											PEGWO	PR_FS	10
G2-EECEPOV	CONCEPTUAL P&C RELAY OVERVIEW	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECRL01	PR_FS	3
											G2-EECRL02	PR_SS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

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Project Item: 2046601
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Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

GEOTECH	GEOTECH	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	10
											PEGWO	PR_FS	0
TSTT01	TELECOM REVIEW	[redacted]	S	[redacted]	S	INFO	ATHA	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
G2-DEDCIE	CIVIL ESTIMATING	[redacted]	A	[redacted]	A	RPRI	JEHE	[redacted]	[redacted]	[redacted]	G2-CEOILCON	PR_FS	0
											G2-CESTRFDN	PR_FS	0
G2-DEDTEAMS	UPDATE TEAMS MATERIAL AND LABOR- PHYISCAL	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-CEOILCON	PR_FS	0
											G2-CESTRFDN	PR_FS	0
											G2-DEDCE02	PR_FS	2
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	0
ENVR01S	SUBSTATION SAMPLING	[redacted]	S	[redacted]	S	CCOL	NLHU	[redacted]	[redacted]	[redacted]	DED01	PR_SS	5
G2-EECEP01	CONCEPTUAL CONTROL DESIGN	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEPOV	PR_FS	0
											G2-EECRL02	PR_FS	0
											G2-SCOPE	PR_FS	2
G2-DEDQAEST	QA PHYSICAL ESTIMATE	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDCIE	PR_FS	0
											G2-DEDTEAMS	PR_FS	0
ALS05	DESIGN GRADING	[redacted]	S	[redacted]	S	DRTH	NFDY	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	0
											ENVR01	PR_FS	5
											REPE2	PR_FS	10
GTSWR	WORK REQUEST SUBMITTAL	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	25
G2-EECEPQA	CONCEPTUAL CONTROL DESIGN REVIEW	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEP01	PR_FS	0
G2-DEDSFED	SHAREHOLDER FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDQAEST	PR_FS	5
CECONTDE	OIL CONTAINMENT DESIGN ENGINEERING	[redacted]	S	[redacted]	S	DRTH	RFIS	[redacted]	[redacted]	[redacted]	CESTRFDN	PR_SS	0
CESTRFDN	CIVIL STRUCTURE REVIEW & FOUNDATION DESIGN	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	DED01	PR_SS	10
											GEOTECH	PR_FS	2
G2-EECEP02	CONCEPTUAL CONTROL DESIGN TRANSMITTAL	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEPQA	PR_FS	0
G2-EECTEAMS	UPDATE TEAMS MATERIAL AND LABOR - CONTROL	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEPQA	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

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Project Item: 2046601
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted], [redacted] [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G2-GTSRVW	CONCEPTUAL TEST REVIEW	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEP02	PR_FS	2
FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	ALS05	PR_FS	4
PEERVW	PEER REVIEW	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED01	PR_FS	0
EECSKQC	P&C QUALITY CONTROL	[redacted]	S	[redacted]	S	PCAS	UNAS	[redacted]	[redacted]	[redacted]	EECSK	PR_FS	5
DEDQA	PHYSICAL ENGINEERING QA	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	ALS05	PR_FS	0
											CECONTDE	PR_FS	0
											CESTRFDN	PR_FS	0
											DED01	PR_FS	0
											PEERVW	PR_FS	0
DED02	TRANSMIT PHYSICAL ENGINEERING	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	DEDQA	PR_FS	0
											G3-GATE3	PR_FF	0
DEDSF	SEND DRAWINGS TO SHOP FAB	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED02	PR_SS	0
G4-GATE4	GATE 4 CONSTRUCTION PHASE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	FCS02	PR_SS	0
											GCS01	PR_SS	0
											GCSEI02	PR_SS	0
											REPE3	PR_SS	0
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CULT01	PR_FS	0
											DED02	PR_FS	0
EECPT	PRELIMINARY TRANSMITTAL	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECSKQC	PR_FS	1
FCS01	BID GRADING	[redacted]	S	[redacted]	S	MSMI		[redacted]	[redacted]	[redacted]	DED02	PR_FS	5
											REPE2	PR_FS	20
EEC01	CONTROL ENGINEERING INDOOR	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	DED01	PR_SS	15
											EECPT	PR_FS	0
											EECSK	PR_FS	0
											EECSKQC	PR_FS	5
											TSTT01	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item:	2046601	Job ID:	2046601
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	5/30/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

EECRQN	REQUISITION CONTROL NON-STOCK MATERIAL	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC01	PR_SS	5
EECQA	CONTROL ENGINEERING QA INDOOR	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC01	PR_FS	0
EEC02	TRANSMIT CONTROL ENGINEERING INDOOR	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECQA	PR_FS	0
											G3-GATE3	PR_FF	0
EECRL01	DESIGN RELAY SETTINGS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EEC02	PR_FS	1
GCW02	SHOP WIRING	[redacted]	S	[redacted]	S	BSMC	UNAS	[redacted]	[redacted]	[redacted]	EEC02	PR_FS	8
											EECRQN	PR_FS	20
FCS02	SUBSTATION GRADING	[redacted]	S	[redacted]	S	MSMI		[redacted]	[redacted]	[redacted]	FCLNOI	PR_FS	4
											FCS01	PR_FS	16
EECRLQC	DESIGN RELAY SETTINGS QC	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EECRL01	PR_FS	0
GTSPQA	PANEL QUALITY ASSURANCE	[redacted]	S	[redacted]	S	TGUA	UNAS	[redacted]	[redacted]	[redacted]	GCW02	PR_FS	12.5
MAJ_EQPT - S	RECEIVE MAJOR EQUIPMENT (Switch)	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	EQPT	PR_FF	0
											PEGWO	PR_FS	5
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEDRQN	PR_SS	5
											EQPT	PR_FF	0
EECRL02	TRANSMIT RELAY SETTINGS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EECRLQC	PR_FS	0
											G3-GATE3	PR_FF	0
GTSREV	TEST REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EEC02	PR_FS	10
											EECRL02	PR_FS	0
EEC03	TRANSMITTAL OF LOGIC DIAGRAM	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECRL02	PR_FS	1
											G3-GATE3	PR_FF	0
EEC11	CONTROL ENGINEERING OUTDOOR	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC01	PR_SS	0
											MAJ_EQPT - S	PR_FS	0
MCS01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEDSF	PR_FS	0
											EQPT	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

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Project Item: 2046601
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											GCS01	PR_SS	-40
											SHIPPING	PR_FS	0
GCS01	SUBSTATION CONSTRUCTION PRE-WORK ([redacted])	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DED02	PR_FS	32
											DEDSF	PR_FS	38.4
											EEC02	PR_FS	24
											ENVR01S	PR_FS	12.8
											FCS02	PR_FS	5
											MAJ_EQPT - S	PR_FS	4
											REPE3	PR_FS	6.4
EECQAO	CONTROL ENGINEERING QA OUTDOOR	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC11	PR_FS	0
EEC12	TRANSMIT CONTROL ENGINEERING OUTDOOR	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECQAO	PR_FS	0
											G3-GATE3	PR_FF	0
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	SUBA	[redacted]	[redacted]	[redacted]	BAS01	PR_FS	0
											DED02	PR_FS	10
											EEC02	PR_FS	10
											EEC12	PR_FS	1
GCSCH	INSTALL CONTROL HOUSE (NOT NEEDED)	[redacted]	A	[redacted]	A	SCOT	UNAS	[redacted]	[redacted]	[redacted]	0		0
GCSEI02	INSTALL EQUIPMENT	[redacted]	S	[redacted]	S	JEWD	UNAS	[redacted]	[redacted]	[redacted]	GCS01	PR_SS	10
OUTAGE	SUB OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	GCS01	PR_SS	0
GCW01	FIELD WIRING	[redacted]	S	[redacted]	S	BSMC	CCOL	[redacted]	[redacted]	[redacted]	GCS01	PR_SS	20
PHYSEC	PHYSICAL SECURITY INTEGRATOR	[redacted]	A	[redacted]	A	MCMA	MCMA	[redacted]	[redacted]	[redacted]	0		0
TSFT	SUB FIBER TERMINATION	[redacted]	A	[redacted]	A	INFO	JGCR	[redacted]	[redacted]	[redacted]	0		0
TSTT02	CIRCUIT INSTALLATION	[redacted]	A	[redacted]	A	INFO	ATHA	[redacted]	[redacted]	[redacted]	0		0
GTS01	TEST & CUT-IN (LOE)	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	GTS01-A1	PR_SS	0
GTS01-A1	TEST & CUT-IN (Engineer 1)	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EEC03	PR_FS	0

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GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046601
OP: FP:
Job Name: EATONTON PRIMARY
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Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											GCW01	PR_SS	0
											GTSPQA	PR_FS	6.25
											GTSREV	PR_FS	10
											GTSWR	PR_FS	0
GTS01-A2	TEST & CUT-IN (Engineer 2)	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EEC03	PR_FS	0
											GCW01	PR_SS	0
											GTS01	PR_FF	0
											GTSPQA	PR_FS	6.25
											GTSREV	PR_FS	10
											GTSWR	PR_FS	0
DED03	FINAL SUBSTATION INSPECTION	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	GCS01	PR_FS	0
											GTS01-A1	PR_FF	-1
											GTS01-A2	PR_FF	-1
DEDAB	AS-BUILT PHYSICAL ENGINEERING	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED03	PR_SS	0
G5-GATE5	GATE 5 CLOSEOUT PHASE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	HPB02	PR_SS	0
HPB02	REQUIRED FINISH / IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DED03	PR_FF	0
											DESC	PR_FF	0
											FCS02	PR_FS	0
											G4-GATE4	PR_FF	0
											GCS01	PR_FS	0
											GCSEI02	PR_FS	0
											GCW01	PR_FS	0
											GTS01-A1	PR_FS	0
											GTS01-A2	PR_FS	0
											GTSFC	PR_FS	0
											MCS01	PR_FS	0

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046601
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046601
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

												OUTAGE	PR_FS	0
												REPE3	PR_FS	0
GTSFC	TEST FIELD CHANGES	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]		GTS01-A1	PR_FS	0
												GTS01-A2	PR_FS	0
EECRL03	PROMOTE PENDING RELAY SETTINGS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]		GTS01-A1	PR_FS	10
												GTS01-A2	PR_FS	5
												HPB02	PR_FS	0
EECAB	AS-BUILT CONTROL ENGINEERING	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]		GTSFC	PR_FS	5
EECFCR	CONTROL ENGINEERING FIELD CHANGE REVIEW	[redacted]	S	[redacted]	S	RACB	X2BP	[redacted]	[redacted]	[redacted]		EECAB	PR_SS	10
WKOC	WORK ORDER CLOSE	[redacted]	S	[redacted]	S	SEHI	SUBA	[redacted]	[redacted]	[redacted]		DEDAB	PR_FS	0
												DESC	PR_FF	0
												EECAB	PR_FS	0
												EECFCR	PR_FS	0
												EECRL03	PR_FS	0
												G5-GATE5	PR_FF	0
												HPB02	PR_FS	60

*** End of Report ***

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:00 PM

Project Item: 2046604
OP: FP:
Job Name: EATONTON PRIMARY - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046604
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

Activity Id	Activity Description	Activity Start	S/A	Activity Finish	S/A	Supv	Eng /For	Org Dur	Rem Dur	Float Total	Predecessor Activity	Pred Type	Lag Days
DESC	EATONTON PRIMARY - OASIS 230KV	[redacted]	A	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
											HPB01	PR_SS	0
G1-GATE1	GATE 1 INITIATION PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
G1-GATE12	SUBMIT GATE 1 TRANSITION (1-20)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE1	PR_FF	0
											G1-PRIOR	PR_FS	0
G1-PRIOR	VALIDATE PROJECT PRIORITIZATION (1-18)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
G1-SCHEDULE	INITIATE LONG RANGE PLANNING SCHEDULE (1-15)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	0		0
DPRTCA	DPRT CONCEPT APPROVAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
											G2-CEDESMET	PR_FS	0
G2-CONCEP	GATE 2 CONCEPTUAL DESIGN PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_SS	0
G2-HPB01	BUDGET APPROVAL (G2)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	0		0
G2-STAKE	STAKEHOLDER NOTIFICATION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE12	PR_FS	10
HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	0		0
DEREST	DISTRIBUTION CONCEPTUAL ESTIMATE REQUEST	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DPRTCA	PR_FS	0
G2-PEGWO	CREATE WORK ORDER	[redacted]	A	[redacted]	A	CRYJ	LINE	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_FS	1
G2-BAS01	SEND & ASSIGN GATE 3 PRELIMINARY BASELINE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-RISKMAN	PR_SS	0
G2-CEDESMET	CONCEPTUAL DESIGN KICKOFF MEETING	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-PEGWO	PR_FS	2
G2-SCOPEPHASE	PROJECT SCOPING PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-STAKE	PR_FS	0
G2-ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	0
G2-ALL01	PRELIMINARY LINE SELECTION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	2
G2-WOSUS	WORK ORDER SUSPENSION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	DESC	PR_FF	0
											G2-BAS01	PR_FS	0
											G2-CONCEP	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046604
OP: FP:
Job Name: EATONTON PRIMARY - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046604
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											G2-FQQF	PR_FS	0
											G2-PSQA	PR_FS	0
											G2-RISKMAN	PR_FS	0
G2-ALS02	FIELD ENGINEERING	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS01	PR_FS	0
G2-ALL02	CONCEPTUAL/FORMAL LINE LOCATION	[redacted]	A	[redacted]	A	DVIN	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL01	PR_FS	0
											G2-CEDESMET	PR_FS	2
EQPT	MATERIALS LOE	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	CELRQN	PR_SS	0
											PEGWO	PR_SS	0
G2-SCOPE	SCOPING MEETING	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL02	PR_FS	2
G3-GATE3	GATE 3 ENGINEERING PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_SS	0
PEGWO	WORK ORDER (CREATE / UNSUSPEND)	[redacted]	S	[redacted]	S	MDPE	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	5
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	0		0
G2-ALS03	OFFICE ENGINEERING	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS02	PR_FS	0
ALS01	PROPERTY OWNER NOTIFICATION (NOT NEEDED)	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
											REPE2	PR_FS	0
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	KKOS	[redacted]	[redacted]	[redacted]	ALS02	PR_FF	0
G2-CELDP	INITIAL PROJECT CONCEPT	[redacted]	A	[redacted]	A	GEGR	GEGR	[redacted]	[redacted]	[redacted]	G2-SCOPE	PR_FS	3
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
DEREST01	DISTRIBUTION CONCEPTUAL DESIGN ENGINEERING	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST	PR_FS	0
G2-ALS03B	SUBMIT PLS-CADD MODEL	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL02	PR_FS	3
											G2-ALS03	PR_FS	0
DELPT01	INITIATE PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_SS	5
G2-CEL01	CONCEPTUAL DESIGN	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS03B	PR_FS	2
											G2-CELDP	PR_FS	2

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046604

OP: FP:

Job Name: EATONTON PRIMARY - OASIS 230KV

Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br

Job Type: MODIFICATION

Area: CENTRAL-ATHENS

In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025

Project Manager: [redacted]

Job ID: 2046604

Job Status: APPROVED

Region: CENTRAL

Owner: GPCO

ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_FF	0
CONRE	CONSTRUCTABLITY REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	0
ALS04A	PRELIMINARY DESIGN STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	4
G2-CELRVW	CONCEPTUAL DESIGN REVIEW	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEL01	PR_FS	0
G2-CFD	CONCEPTUAL FOUNDATION DESIGN	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-CEL01	PR_FS	0
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS04A	PR_FS	0
											CEL01	PR_FS	0
											CONRE	PR_FS	0
DLDP	DESIGN L&D PACKAGE	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	5
G2-CELPKT	CONCEPTUAL PACKAGE TRANSMITTAL	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CELRVW	PR_FS	0
											G2-CFD	PR_FS	0
ALS03B	SUBMIT PLS-CADD MODEL	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	0
											ENVR01	PR_FS	0
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
FCL05	SOIL BORING CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	CEL01A	PR_SS	-4
G2-CONSFED	SHAREHOLDER FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	2
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JMIS	WWAN	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	5
											CEL01	PR_SS	5
											ENVR01	PR_FS	5
CEL01A	SOIL BORING	[redacted]	S	[redacted]	S	MSMI	DRTH	[redacted]	[redacted]	[redacted]	ALS04A	PR_FS	0
											CELRVW	PR_FS	5
G2-PSQA	PROJECT SUPPORT QA/QC	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	0
											G2-CONSFED	PR_FS	0
G2-PREOUTAGE	PRELIMINARY OUTAGE COORDINATION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	5
											G2-CONSFED	PR_FF	2

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:00 PM

Project Item: 2046604
OP: FP:
Job Name: EATONTON PRIMARY - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046604
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G2-FQQF	FINAL QA/QC FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CONSFED	PR_FS	0
											G2-PSQA	PR_SS	3
G2-RISKMAN	UPDATE RISK MANAGEMENT PLAN	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-PREOUTAGE	PR_FS	4
CEL01B	SCS - DESIGN FOUNDATIONS	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	CEL01A	PR_FS	0
											DEL01	PR_SS	5
											G3-GATE3	PR_FF	0
CEL01D	APPROVE MFR. CALCULATIONS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DLDP	PR_FS	20
DESF	DRILLED PIER FOUNDATION DESIGN	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	CEL01A	PR_FS	6.25
											CEL01D	PR_FS	5
											DEL01	PR_FS	0
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
											CEL01B	PR_FS	0
											CEL01D	PR_FS	10
											DEL01	PR_FS	0
DELPT02	RECEIVE PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	40
											G3-GATE3	PR_FF	0
DPFR	DRILLED PIER FOUNDATION DESIGN REVIEW	[redacted]	A	[redacted]	A	MSMI	EPSH	[redacted]	[redacted]	[redacted]	DESF	PR_FS	0
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	0
											EQPT	PR_FF	0
CEL01C	APPROVE MFR. DRAWINGS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	40
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01C	PR_FS	0
											DEL01	PR_FS	0
											DPFR	PR_FS	0
											G3-GATE3	PR_FF	0
DEREST02	DISTRIBUTION CONCEPTUAL ESTIMATE SUBMITTAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST01	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046604
OP: FP:
Job Name: EATONTON PRIMARY - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046604
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	ALS06	PR_FS	16
											FCL01	PR_SS	-21
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
BIDFD	BID FOUNDATIONS	[redacted]	S	[redacted]	S	MSMI	EPSH	[redacted]	[redacted]	[redacted]	CEL01B	PR_FS	10
											DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
ALS04B	CLEAR R/W STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	8
											FCL01	PR_SS	-10
DISTEASE	DISTRIBUTION EASEMENT	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTMAT	DISTRIBUTION ORDER LONG LEAD MATERIAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTPERM	DISTRIBUTION PERMITTING	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DPRTFAP	DPRT/ BEST PRACTICE FINAL APPROVAL FOR DISTRIBUTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	BIDFCL	PR_FS	10
											DEL02	PR_FS	8
											DELPT02	PR_FS	6.4
G4-GATE4	GATE 4 CONSTRUCTION PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	FCL01	PR_SS	0
											FCL03	PR_SS	0
											GCL01	PR_SS	0
											GCLFD	PR_SS	0
											OUTAGE	PR_SS	0
											REPE3	PR_SS	0
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	40
											EEGREV	PR_FS	10
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	EQPT	PR_FF	0
											GCL01	PR_SS	-40
											SHIPPING	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046604
OP: FP:
Job Name: EATONTON PRIMARY - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046604
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

MCLFD	RECEIVE ANCHOR BOLTS MATLS	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	CEL01C	PR_FS	0
											CELRQN	PR_FS	70
											EQPT	PR_FF	0
											GCLFD	PR_SS	-25
ALS04C	FOUNDATION STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	GCLFD	PR_SS	-10
FCL04	FOUNDATION CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DELPT02	PR_FS	0
											FCLNOI	PR_FS	0
											GCLFD	PR_SS	-4
ALS04D	FINAL STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	GCL01	PR_SS	-10
GCLFD	INSTALL FOUNDATIONS	[redacted]	S	[redacted]	S	MSMI	KEWH	[redacted]	[redacted]	[redacted]	BIDFD	PR_FS	8
											CEL01B	PR_FS	0
											DEL02	PR_FS	0
											DELPT02	PR_FS	6.4
											FCLNOI	PR_FS	6.4
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DELPT02	PR_FS	0
											FCLNOI	PR_FS	4
											GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION ([redacted])	[redacted]	S	[redacted]	S	LTOW	UNAS	[redacted]	[redacted]	[redacted]	CULT01	PR_FS	0
											DEL02	PR_FS	24
											DELPT02	PR_FS	6.4
											FCLNOI	PR_FS	8
											GCLFD	PR_SS	0
											REPE3	PR_FS	9.6
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	GCL01	PR_FF	0
GCL02	COMPLETE COUNTERPOISE (3 POLES)	[redacted]	S	[redacted]	S	DBSH	DBSH	[redacted]	[redacted]	[redacted]	GCL01	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046604
OP: FP:
Job Name: EATONTON PRIMARY - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046604
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G5-GATE5	GATE 5 CLOSEOUT PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	HPB02	PR_SS	0
HPB02	REQUIRED FINISH / IN-SERVICE DATE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	ALS04B	PR_FS	0
											ALS04C	PR_FS	0
											ALS04D	PR_FS	0
											DEL03	PR_FS	0
											DESC	PR_FF	0
											FCL03	PR_FS	0
											FCL04	PR_FS	0
											FCL05	PR_FS	0
											FCLNOI	PR_FS	0
											G4-GATE4	PR_FF	0
											GCL01	PR_FS	0
											GCL02	PR_FS	0
											MCL01	PR_FS	0
											MCLFD	PR_FS	0
											OUTAGE	PR_FS	0
											REPE3	PR_FS	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	DEL03	PR_FS	4
DISTJPS	DISTRIBUTION JOB PACKAGE SUBMITTAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTEASE	PR_FS	0
											DISTPERM	PR_FS	0
											DPRTFAP	PR_FS	0
DISTOHC	DISTRIBUTION OVERHEAD CONSTRUCTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTUDC	DISTRIBUTION UNDERGROUND CONSTRUCTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTCC	DISTRIBUTION CONSTRUCTION COMPLETION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTOHC	PR_FS	0
											DISTUDC	PR_FS	0
DISTWOC	DISTRIBUTION FIELD CLOSE	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTCC	PR_FS	40

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:00 PM

Project Item:	2046604	Job ID:	2046604
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY - OASIS 230KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-ATHENS		
In Service Date:	5/2/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	ALS02F	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS02F	PR_FS	0
											ALS03F	PR_SS	10
DELWOC	WORK ORDER CLOSE	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DELDOC	PR_FS	0
											DESC	PR_FF	0
											G5-GATE5	PR_FF	0
											HPB02	PR_FS	60

*** End of Report ***

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:01 PM

Project Item: 2046605
OP: FP:
Job Name: BRANCH - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046605
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

Activity Id	Activity Description	Activity Start	S/A	Activity Finish	S/A	Supv	Eng /For	Org Dur	Rem Dur	Float Total	Predecessor Activity	Pred Type	Lag Days
DESC	BRANCH - OASIS 230KV	[redacted]	A	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
											HPB01	PR_SS	0
G1-GATE1	GATE 1 INITIATION PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
G1-GATE12	SUBMIT GATE 1 TRANSITION (1-20)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE1	PR_FF	0
											G1-PRIOR	PR_FS	0
G1-PRIOR	VALIDATE PROJECT PRIORITIZATION (1-18)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
G1-SCHEDULE	INITIATE LONG RANGE PLANNING SCHEDULE (1-15)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	0		0
DPRTCA	DPRT CONCEPT APPROVAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
											G2-CEDESMET	PR_FS	0
G2-CONCEP	GATE 2 CONCEPTUAL DESIGN PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_SS	0
G2-HPB01	BUDGET APPROVAL (G2)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	0		0
G2-STAKE	STAKEHOLDER NOTIFICATION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE12	PR_FS	10
HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	0		0
DEREST	DISTRIBUTION CONCEPTUAL ESTIMATE REQUEST	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DPRTCA	PR_FS	0
G2-PEGWO	CREATE WORK ORDER	[redacted]	A	[redacted]	A	CRYJ	LINE	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_FS	1
G2-CEDESMET	CONCEPTUAL DESIGN KICKOFF MEETING	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-PEGWO	PR_FS	2
G2-SCOPEPHASE	PROJECT SCOPING PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-STAKE	PR_FS	0
G2-ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	0
G2-ALL01	PRELIMINARY LINE SELECTION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	2
G2-BAS01	SEND & ASSIGN GATE 3 PRELIMINARY BASELINE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-RISKMAN	PR_SS	0
G2-WOSUS	WORK ORDER SUSPENSION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	DESC	PR_FF	0
											G2-BAS01	PR_FS	0
											G2-CONCEP	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:01 PM

Project Item:	2046605	Job ID:	2046605
OP: FP:		Job Status:	APPROVED
Job Name:	BRANCH - OASIS 230KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-ATHENS		
In Service Date:	5/2/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

											G2-FQQF	PR_FS	0
											G2-PSQA	PR_FS	0
											G2-RISKMAN	PR_FS	0
G2-ALS02	FIELD ENGINEERING	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS01	PR_FS	0
G2-ALL02	CONCEPTUAL/FORMAL LINE LOCATION	[redacted]	A	[redacted]	A	DVIN	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL01	PR_FS	0
											G2-CEDESMET	PR_FS	2
EQPT	MATERIALS LOE	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	CELRQN	PR_SS	0
											PEGWO	PR_SS	0
G2-SCOPE	SCOPING MEETING	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL02	PR_FS	2
G3-GATE3	GATE 3 ENGINEERING PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_SS	0
PEGWO	WORK ORDER (CREATE / UNSUSPEND)	[redacted]	S	[redacted]	S	MDPE	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	5
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	0		0
G2-ALS03	OFFICE ENGINEERING	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS02	PR_FS	0
ALS01	PROPERTY OWNER NOTIFICATION (NOT NEEDED)	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
											REPE2	PR_FS	0
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	KKOS	[redacted]	[redacted]	[redacted]	ALS02	PR_FF	0
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_FF	0
G2-CELDP	INITIAL PROJECT CONCEPT	[redacted]	A	[redacted]	A	GEGR	GEGR	[redacted]	[redacted]	[redacted]	G2-SCOPE	PR_FS	3
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
DEREST01	DISTRIBUTION CONCEPTUAL DESIGN ENGINEERING	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST	PR_FS	0
G2-ALS03B	SUBMIT PLS-CADD MODEL	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL02	PR_FS	3
											G2-ALS03	PR_FS	0
DELPT01	INITIATE PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_SS	5
G2-CEL01	CONCEPTUAL DESIGN	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS03B	PR_FS	2

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046605
OP: FP:
Job Name: BRANCH - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046605
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											G2-CELDP	PR_FS	2
CONRE	CONSTRUCTABLITY REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	0
ALS04A	PRELIMINARY DESIGN STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	4
G2-CELRVW	CONCEPTUAL DESIGN REVIEW	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEL01	PR_FS	0
G2-CFD	CONCEPTUAL FOUNDATION DESIGN	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-CEL01	PR_FS	0
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS04A	PR_FS	0
											CEL01	PR_FS	0
											CONRE	PR_FS	0
G2-CELPKT	CONCEPTUAL PACKAGE TRANSMITTAL	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CELRVW	PR_FS	0
											G2-CFD	PR_FS	0
ALS03B	SUBMIT PLS-CADD MODEL	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	0
											ENVR01	PR_FS	0
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
FCL05	SOIL BORING CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	CEL01A	PR_SS	-4
G2-CONSFED	SHAREHOLDER FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	2
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JMIS	WWAN	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	5
											CEL01	PR_SS	5
											ENVR01	PR_FS	5
CEL01A	SOIL BORING	[redacted]	S	[redacted]	S	MSMI	DRTH	[redacted]	[redacted]	[redacted]	ALS04A	PR_FS	0
											CELRVW	PR_FS	5
DLDP	DESIGN L&D PACKAGE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	5
G2-PSQA	PROJECT SUPPORT QA/QC	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	0
											G2-CONSFED	PR_FS	0
G2-PREOUTAGE	PRELIMINARY OUTAGE COORDINATION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	5
											G2-CONSFED	PR_FF	2

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:01 PM

Project Item:	2046605	Job ID:	2046605
OP: FP:		Job Status:	APPROVED
Job Name:	BRANCH - OASIS 230KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-ATHENS		
In Service Date:	5/2/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

G2-FQQF	FINAL QA/QC FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CONSFED	PR_FS	0
											G2-PSQA	PR_SS	3
G2-RISKMAN	UPDATE RISK MANAGEMENT PLAN	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-PREOUTAGE	PR_FS	4
CEL01B	SCS - DESIGN FOUNDATIONS	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	CEL01A	PR_FS	0
											DEL01	PR_SS	5
											G3-GATE3	PR_FF	0
CEL01D	APPROVE MFR. CALCULATIONS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DLDP	PR_FS	20
DELPT02	RECEIVE PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	40
											G3-GATE3	PR_FF	0
DESF	DRILLED PIER FOUNDATION DESIGN	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	CEL01A	PR_FS	6.25
											CEL01D	PR_FS	5
											DEL01	PR_FS	0
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
											CEL01B	PR_FS	0
											CEL01D	PR_FS	10
											DEL01	PR_FS	0
DPFR	DRILLED PIER FOUNDATION DESIGN REVIEW	[redacted]	S	[redacted]	S	MSMI	EPSH	[redacted]	[redacted]	[redacted]	DESF	PR_FS	0
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	0
											EQPT	PR_FF	0
CEL01C	APPROVE MFR. DRAWINGS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	40
DEREST02	DISTRIBUTION CONCEPTUAL ESTIMATE SUBMITTAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST01	PR_FS	0
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01C	PR_FS	0
											DEL01	PR_FS	0
											DPFR	PR_FS	0
											G3-GATE3	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046605
OP: FP:
Job Name: BRANCH - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046605
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	ALS06	PR_FS	16
											FCL01	PR_SS	-21
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
BIDFD	BID FOUNDATIONS	[redacted]	S	[redacted]	S	MSMI	EPSH	[redacted]	[redacted]	[redacted]	CEL01B	PR_FS	10
											DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
DISTEASE	DISTRIBUTION EASEMENT	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTMAT	DISTRIBUTION ORDER LONG LEAD MATERIAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTPERM	DISTRIBUTION PERMITTING	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DPRTFAP	DPRT/ BEST PRACTICE FINAL APPROVAL FOR DISTRIBUTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
ALS04B	CLEAR R/W STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	8
											FCL01	PR_SS	-10
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	BIDFCL	PR_FS	10
											DEL02	PR_FS	8
											DELPT02	PR_FS	6.4
G4-GATE4	GATE 4 CONSTRUCTION PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	FCL01	PR_SS	0
											FCL03	PR_SS	0
											GCL01	PR_SS	0
											GCLFD	PR_SS	0
											OUTAGE	PR_SS	0
											REPE3	PR_SS	0
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	40
											EEGREV	PR_FS	10
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	EQPT	PR_FF	0
											GCL01	PR_SS	-40
											SHIPPING	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:01 PM

Project Item: 2046605
OP: FP:
Job Name: BRANCH - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046605
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

MCLFD	RECEIVE ANCHOR BOLTS MATLS	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	CEL01C	PR_FS	0
											CELRQN	PR_FS	70
											EQPT	PR_FF	0
											GCLFD	PR_SS	-25
ALS04C	FOUNDATION STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	GCLFD	PR_SS	-10
FCL04	FOUNDATION CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DELPT02	PR_FS	0
											FCLNOI	PR_FS	0
											GCLFD	PR_SS	-4
ALS04D	FINAL STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	GCL01	PR_SS	-10
GCLFD	INSTALL FOUNDATIONS	[redacted]	S	[redacted]	S	MSMI	KEWH	[redacted]	[redacted]	[redacted]	BIDFD	PR_FS	8
											CEL01B	PR_FS	0
											DEL02	PR_FS	0
											DELPT02	PR_FS	6.4
											FCLNOI	PR_FS	6.4
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DELPT02	PR_FS	0
											FCLNOI	PR_FS	4
											GCL01	PR_SS	-5
GCL01	LINE CONSTRUCTION ([redacted])	[redacted]	S	[redacted]	S	LBDA	UNAS	[redacted]	[redacted]	[redacted]	CULT01	PR_FS	0
											DEL02	PR_FS	24
											DELPT02	PR_FS	6.4
											FCLNOI	PR_FS	8
											GCLFD	PR_SS	0
											REPE3	PR_FS	9.6
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	GCL01	PR_FF	0
GCL02	COMPLETE COUNTERPOISE (3 POLES)	[redacted]	S	[redacted]	S	DBSH	DBSH	[redacted]	[redacted]	[redacted]	GCL01	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046605
OP: FP:
Job Name: BRANCH - OASIS 230KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-ATHENS
In Service Date: 5/2/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046605
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G5-GATE5	GATE 5 CLOSEOUT PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	HPB02	PR_SS	0
HPB02	REQUIRED FINISH / IN-SERVICE DATE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	ALS04B	PR_FS	0
											ALS04C	PR_FS	0
											ALS04D	PR_FS	0
											DEL03	PR_FS	0
											DESC	PR_FF	0
											FCL03	PR_FS	0
											FCL04	PR_FS	0
											FCL05	PR_FS	0
											FCLNOI	PR_FS	0
											G4-GATE4	PR_FF	0
											GCL01	PR_FS	0
											GCL02	PR_FS	0
											MCL01	PR_FS	0
											MCLFD	PR_FS	0
											OUTAGE	PR_FS	0
											REPE3	PR_FS	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	DEL03	PR_FS	4
DISTJPS	DISTRIBUTION JOB PACKAGE SUBMITTAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTEASE	PR_FS	0
											DISTPERM	PR_FS	0
											DPRTFAP	PR_FS	0
DISTOHC	DISTRIBUTION OVERHEAD CONSTRUCTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTUDC	DISTRIBUTION UNDERGROUND CONSTRUCTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTCC	DISTRIBUTION CONSTRUCTION COMPLETION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTOHC	PR_FS	0
											DISTUDC	PR_FS	0
DISTWOC	DISTRIBUTION FIELD CLOSE	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTCC	PR_FS	40

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:01 PM

Project Item:	2046605	Job ID:	2046605
OP: FP:		Job Status:	APPROVED
Job Name:	BRANCH - OASIS 230KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-ATHENS		
In Service Date:	5/2/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	ALS02F	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS02F	PR_FS	0
											ALS03F	PR_SS	10
DELWOC	WORK ORDER CLOSE	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DELDOC	PR_FS	0
											DESC	PR_FF	0
											G5-GATE5	PR_FF	0
											HPB02	PR_FS	60

*** End of Report ***

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item: 2046606
OP: FP:
Job Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 11/14/2024 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046606
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

Activity Id	Activity Description	Activity Start	S/A	Activity Finish	S/A	Supv	Eng /For	Org Dur	Rem Dur	Float Total	Predecessor Activity	Pred Type	Lag Days
DESC	EATONTON PRIMARY 190442 - RAYONIER 46 KV	[redacted]	A	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
											HPB01	PR_SS	0
G1-GATE1	GATE 1 INITIATION PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
G1-GATE12	SUBMIT GATE 1 TRANSITION (1-20)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE1	PR_FF	0
											G1-PRIOR	PR_FS	0
G1-PRIOR	VALIDATE PROJECT PRIORITIZATION (1-18)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
G1-SCHEDULE	INITIATE LONG RANGE PLANNING SCHEDULE (1-15)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	0		0
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	A	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	0
											EQPT	PR_FF	0
G2-ALS01	PROPERTY OWNER NOTIFICATION	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	0
G2-CEDESMET	CONCEPTUAL DESIGN KICKOFF MEETING	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-PEGWO	PR_FS	2
G2-CONCEP	GATE 2 CONCEPTUAL DESIGN PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_SS	0
G2-HPB01	BUDGET APPROVAL (G2)	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	0		0
G2-PREOUTAGE	PRELIMINARY OUTAGE COORDINATION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	5
											G2-CONSFED	PR_FF	2
G2-RISKMAN	UPDATE RISK MANAGEMENT PLAN	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-PREOUTAGE	PR_FS	4
G2-SCOPEPHASE	PROJECT SCOPING PHASE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-STAKE	PR_FS	0
G2-STAKE	STAKEHOLDER NOTIFICATION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE12	PR_FS	10
HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	0		0
G2-ALL01	PRELIMINARY LINE SELECTION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	2
G2-PEGWO	CREATE WORK ORDER	[redacted]	A	[redacted]	A	CRYJ	LINE	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_FS	1
DPRTCA	DPRT CONCEPT APPROVAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
											G2-CEDESMET	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item: 2046606
OP: FP:
Job Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 11/14/2024 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046606
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G2-ALS02	FIELD ENGINEERING	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS01	PR_FS	0
G2-BAS01	SEND & ASSIGN GATE 3 PRELIMINARY BASELINE	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	G2-RISKMAN	PR_SS	0
DEREST	DISTRIBUTION CONCEPTUAL ESTIMATE REQUEST	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DPRTCA	PR_FS	0
G2-ALL02	CONCEPTUAL/FORMAL LINE LOCATION	[redacted]	A	[redacted]	A	DVIN	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL01	PR_FS	0
											G2-CEDESMET	PR_FS	2
G2-SCOPE	SCOPING MEETING	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL02	PR_FS	2
G2-ALS03	OFFICE ENGINEERING	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS02	PR_FS	0
G2-CELDP	INITIAL PROJECT CONCEPT	[redacted]	A	[redacted]	A	GEGR	GEGR	[redacted]	[redacted]	[redacted]	G2-SCOPE	PR_FS	3
EQPT	MATERIALS LOE	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	CELRQN	PR_SS	0
											PEGWO	PR_SS	0
G3-GATE3	GATE 3 ENGINEERING PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_SS	0
PEGWO	WORK ORDER (CREATE / UNSUSPEND)	[redacted]	S	[redacted]	S	MDPE	LINE	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	5
REPE2	SET UP PRE-ENGINEERING CONFERENCE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	0		0
ALS01	PROPERTY OWNER NOTIFICATION (NOT NEEDED)	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	0
											REPE2	PR_FS	0
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	KKOS	[redacted]	[redacted]	[redacted]	ALS02	PR_FF	0
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	S	[redacted]	S	JJCA	DMRI	[redacted]	[redacted]	[redacted]	ALS02	PR_FF	0
G2-ALS03B	SUBMIT PLS-CADD MODEL	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL02	PR_FS	3
											G2-ALS03	PR_FS	0
G2-CEL01	CONCEPTUAL DESIGN	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-ALS03B	PR_FS	2
											G2-CELDP	PR_FS	2
ALS02	FIELD ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
CEL01	PRELIMINARY ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
DELPT01	INITIATE PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_SS	5
DEREST01	DISTRIBUTION CONCEPTUAL DESIGN ENGINEERING	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item: 2046606
OP: FP:
Job Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 11/14/2024 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046606
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G2-CELRVW	CONCEPTUAL DESIGN REVIEW	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEL01	PR_FS	0
G2-CFD	CONCEPTUAL FOUNDATION DESIGN	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-CEL01	PR_FS	0
CONRE	CONSTRUCTABLITY REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
ALS04A	PRELIMINARY DESIGN STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	4
G2-CELPKT	CONCEPTUAL PACKAGE TRANSMITTAL	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CELRVW	PR_FS	0
											G2-CFD	PR_FS	0
ALS03	OFFICE ENGINEERING	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	6.25
CELRVW	PRELIM LINE DESIGN REVIEW	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS04A	PR_FS	0
											CEL01	PR_FS	0
											CONRE	PR_FS	0
G2-CONSFED	SHAREHOLDER FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	2
DEL01	FINAL LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	0
FCL05	SOIL BORING CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	CEL01A	PR_SS	-4
G2-PSQA	PROJECT SUPPORT QA/QC	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-CELPKT	PR_FS	0
											G2-CONSFED	PR_FS	0
G2-FQQF	FINAL QA/QC FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CONSFED	PR_FS	0
											G2-PSQA	PR_SS	3
CEL01A	SOIL BORING	[redacted]	S	[redacted]	S	MSMI	DRTH	[redacted]	[redacted]	[redacted]	ALS04A	PR_FS	0
											CELRVW	PR_FS	5
DLDP	DESIGN L&D PACKAGE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRVW	PR_FS	5
ALS03B	SUBMIT PLS-CADD MODEL	[redacted]	S	[redacted]	S	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	5
											ENVR01	PR_FS	0
ALS06	ENGINEERING STORMWATER PLAN	[redacted]	S	[redacted]	S	JMIS	WWAN	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	5
											CEL01	PR_SS	5
											ENVR01	PR_FS	5
G2-WOSUS	WORK ORDER SUSPENSION	[redacted]	A	[redacted]	A	CRYJ	ANAL	[redacted]	[redacted]	[redacted]	DESC	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item:	2046606	Job ID:	2046606
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY 190442 - RAYONIER 46 KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	11/14/2024 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

											G2-BAS01	PR_FS	0
											G2-CONCEP	PR_FF	0
											G2-FQQF	PR_FS	0
											G2-PSQA	PR_FS	0
											G2-RISKMAN	PR_FS	0
CEL01B	SCS - DESIGN FOUNDATIONS	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	CEL01A	PR_FS	0
											DEL01	PR_SS	5
											G3-GATE3	PR_FF	0
CEL01D	APPROVE MFR. CALCULATIONS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DLDP	PR_FS	20
DELPT02	RECEIVE PERMIT	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DELPT01	PR_FS	40
											G3-GATE3	PR_FF	0
CELRQN	ORDER LONG LEAD MATERIALS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01	PR_FS	0
											CEL01B	PR_FS	0
											CEL01D	PR_FS	5
											DEL01	PR_FS	0
DESF	DRILLED PIER FOUNDATION DESIGN	[redacted]	S	[redacted]	S	DRTH	GWAS	[redacted]	[redacted]	[redacted]	CEL01A	PR_FS	6.25
											CEL01D	PR_FS	5
											DEL01	PR_FS	0
DPFR	DRILLED PIER FOUNDATION DESIGN REVIEW	[redacted]	S	[redacted]	S	MSMI	EPSH	[redacted]	[redacted]	[redacted]	DESF	PR_FS	0
CEL01C	APPROVE MFR. DRAWINGS	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CELRQN	PR_FS	40
DEL02	TRANSMIT LINE ENGINEERING	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	CEL01C	PR_FS	0
											DEL01	PR_FS	0
											DPFR	PR_FS	0
											G3-GATE3	PR_FF	0
DEREST02	DISTRIBUTION CONCEPTUAL ESTIMATE SUBMITTAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST01	PR_FS	0
FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	ALS06	PR_FS	8

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046606
OP: FP:
Job Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 11/14/2024 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046606
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											FCL01	PR_SS	-21
BIDFCL	BID CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
BIDFD	BID FOUNDATIONS	[redacted]	S	[redacted]	S	MSMI	EPSH	[redacted]	[redacted]	[redacted]	CEL01B	PR_FS	10
											DEL02	PR_FS	10
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	10
MCLFD	RECEIVE ANCHOR BOLTS MATLS	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	CEL01C	PR_FS	0
											CELRQN	PR_FS	70
											EQPT	PR_FF	0
											GCLFD	PR_SS	-25
ALS04B	CLEAR R/W STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	DEL01	PR_FS	8
											FCL01	PR_SS	-10
ALS04C	FOUNDATION STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	GCLFD	PR_SS	-10
ALS04D	FINAL STAKING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	GCL01	PR_SS	-10
DISTEASE	DISTRIBUTION EASEMENT	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTMAT	DISTRIBUTION ORDER LONG LEAD MATERIAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTPERM	DISTRIBUTION PERMITTING	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DPRTFAP	DPRT/ BEST PRACTICE FINAL APPROVAL FOR DISTRIBUTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
FCL03	CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DELPT02	PR_FS	0
											FCLNOI	PR_FS	4
											GCL01	PR_SS	-5
FCL04	FOUNDATION CREW SUPPORT	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	DELPT02	PR_FS	0
											FCLNOI	PR_FS	0
											GCLFD	PR_SS	-4
G4-GATE4	GATE 4 CONSTRUCTION PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	FCL01	PR_SS	0
											FCL03	PR_SS	0
											GCL01	PR_SS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item: 2046606
OP: FP:
Job Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 11/14/2024 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046606
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											GCLFD	PR_SS	0
											OUTAGE	PR_SS	0
											REPE3	PR_SS	0
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DEL02	PR_FS	30
											EEGREV	PR_FS	10
MCL01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	EQPT	PR_FF	0
											GCL01	PR_SS	-40
											SHIPPING	PR_FS	0
FCL01	CLEAR R/W	[redacted]	S	[redacted]	S	GEGI	UNAS	[redacted]	[redacted]	[redacted]	BIDFCL	PR_FS	10
											DEL02	PR_FS	8
											DELPT02	PR_FS	6.4
GCL01	LINE CONSTRUCTION ([redacted])	[redacted]	S	[redacted]	S	LBDA	UNAS	[redacted]	[redacted]	[redacted]	CULT01	PR_FS	0
											DEL02	PR_FS	24
											DELPT02	PR_FS	6.4
											FCLNOI	PR_FS	8
											GCLFD	PR_SS	0
											REPE3	PR_FS	0
GCLFD	INSTALL FOUNDATIONS	[redacted]	S	[redacted]	S	MSMI	KEWH	[redacted]	[redacted]	[redacted]	BIDFD	PR_FS	8
											CEL01B	PR_FS	0
											DEL02	PR_FS	0
											DELPT02	PR_FS	6.4
											FCLNOI	PR_FS	8.8
OUTAGE	LINE OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	GCL01	PR_SS	0
DEL03	FINAL INSPECTION	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	GCL01	PR_FF	0
G5-GATE5	GATE 5 CLOSEOUT PHASE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	HPB02	PR_SS	0
GCL02	COMPLETE COUNTERPOISE (5 POLES)	[redacted]	S	[redacted]	S	DBSH	DBSH	[redacted]	[redacted]	[redacted]	GCL01	PR_FF	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item:	2046606	Job ID:	2046606
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY 190442 - RAYONIER 46 KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	11/14/2024 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

HPB02	REQUIRED FINISH / IN-SERVICE DATE	[redacted]	S	[redacted]	S	MDPE	ANAL	[redacted]	[redacted]	[redacted]	ALS04B	PR_FS	0
											ALS04C	PR_FS	0
											ALS04D	PR_FS	0
											DEL03	PR_FF	0
											DESC	PR_FF	0
											FCL03	PR_FS	0
											FCL04	PR_FS	0
											FCL05	PR_FS	0
											FCLNOI	PR_FS	0
											G4-GATE4	PR_FF	0
											GCL01	PR_FF	0
											GCL02	PR_FF	0
											OUTAGE	PR_FF	0
											REPE3	PR_FS	0
ALS02F	AS-BUILT FIELD ENGINEERING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	DEL03	PR_FS	4
ALS03F	AS-BUILT OFFICE ENGINEERING	[redacted]	S	[redacted]	S	GASC	FCAR	[redacted]	[redacted]	[redacted]	ALS02F	PR_FS	0
DELDOC	ENGINEERING JOB CLOSE	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	ALS02F	PR_FS	0
											ALS03F	PR_SS	10
DELWOC	WORK ORDER CLOSE	[redacted]	S	[redacted]	S	SEHI	LINE	[redacted]	[redacted]	[redacted]	DELDOC	PR_FS	0
											DESC	PR_FF	0
											G5-GATE5	PR_FF	0
											HPB02	PR_FS	60
DISTJPS	DISTRIBUTION JOB PACKAGE SUBMITTAL	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTEASE	PR_FS	0
											DISTPERM	PR_FS	0
											DPRTFAP	PR_FS	0
DISTOHC	DISTRIBUTION OVERHEAD CONSTRUCTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:03 PM

Project Item:	2046606	Job ID:	2046606
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY 190442 - RAYONIER 46 KV	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	11/14/2024 (Scheduled)	Facility Required Date:	6/1/2025
Project Manager:	[redacted]		

DISTUDC	DISTRIBUTION UNDERGROUND CONSTRUCTION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTCC	DISTRIBUTION CONSTRUCTION COMPLETION	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTOHC	PR_FS	0
											DISTUDC	PR_FS	0
DISTWOC	DISTRIBUTION FIELD CLOSE	[redacted]	A	[redacted]	A	MDPE	ANAL	[redacted]	[redacted]	[redacted]	DISTCC	PR_FS	40

*** End of Report ***

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:04 PM

Project Item: 2046607
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046607
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

Activity Id	Activity Description	Activity Start	S/A	Activity Finish	S/A	Supv	Eng /For	Org Dur	Rem Dur	Float Total	Predecessor Activity	Pred Type	Lag Days
DESC	EATONTON PRIMARY SUB	[redacted]	A	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
											HPB01	PR_SS	0
G1-GATE1	GATE 1 INITIATION PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_SS	0
G1-GATE12	SUBMIT GATE 1 TRANSITION (1-20)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE1	PR_FF	0
											G1-PRIOR	PR_FS	0
G1-PRIOR	VALIDATE PROJECT PRIORITIZATION (1-18)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
G1-SCHEDULE	INITIATE LONG RANGE PLANNING SCHEDULE (1-15)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
DEREST	DISTRIBUTION CONCEPTUAL ESTIMATE REQUEST (NOT NEEDED)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DPRTCA	PR_FS	0
DEREST01	DISTRIBUTION CONCEPTUAL DESIGN ENGINEERING	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST	PR_FS	0
DEREST02	DISTRIBUTION CONCEPTUAL ESTIMATE SUBMITTAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST01	PR_FS	0
DISTCC	DISTRIBUTION CONSTRUCTION COMPLETION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTOHC	PR_FS	0
											DISTUDC	PR_FS	0
DISTEASE	DISTRIBUTION EASEMENT	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTJPS	DISTRIBUTION JOB PACKAGE SUBMITTAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTEASE	PR_FS	0
											DISTPERM	PR_FS	0
											DPRTFAP	PR_FS	0
DISTMAT	DISTRIBUTION ORDER LONG LEAD MATERIAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTOHC	DISTRIBUTION OVERHEAD CONSTRUCTION (NOT NEEDED)	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTPERM	DISTRIBUTION PERMITTING	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
DISTUDC	DISTRIBUTION UNDERGROUND CONSTRUCTION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTJPS	PR_FS	0
DISTWOC	DISTRIBUTION FIELD CLOSE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DISTCC	PR_FS	40
DPRTCA	DPRT CONCEPT APPROVAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-SCHEDULE	PR_FS	0
											G2-CEDESMET	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:04 PM

Project Item: 2046607
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046607
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

DPRTFAP	DPRT/ BEST PRACTICE FINAL APPROVAL FOR DISTRIBUTION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEREST02	PR_FS	0
G2-ALL03	CONCEPTUAL/FORMAL SITE LOCATION (NOT NEEDED)	[redacted]	A	[redacted]	A	RAWE	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDCE01	PR_FS	3
G2-SCOPEPHASE	PROJECT SCOPING PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-STAKE	PR_FS	0
G2-CEDESMET	CONCEPTUAL DESIGN KICKOFF MEETING	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-PEGWO	PR_FS	2
G2-RISKMAN	UPDATE RISK MANAGEMENT PLAN	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-GTSRVW	PR_FS	0
											G2-PREOUTAGE	PR_FS	0
G2-STAKE	STAKEHOLDER NOTIFICATION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G1-GATE12	PR_FS	10
HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-WOSUS	PR_FS	0
G2-CONCEP	GATE 2 CONCEPTUAL DESIGN PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_SS	0
G2-HPB01	BUDGET APPROVAL	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-SCOPEPHASE	PR_SS	0
G2-DEDCE01	PRELIMINARY CONCEPTUAL DESIGN PLAN DWG	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	3
G2-PREOUTAGE	PRELIMINARY OUTAGE COORDINATION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-DEDQAEST	PR_FS	2
											G2-DEDSFED	PR_FS	2
											G2-GTSRVW	PR_FS	2
G2-PEGWO	CREATE WORK ORDER	[redacted]	A	[redacted]	A	HLUN	SUBA	[redacted]	[redacted]	[redacted]	G2-HPB01	PR_FS	3
G2-WOSUS	WORK ORDER SUSPENSION	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DESC	PR_FF	0
											G2-ALS013	PR_FS	0
											G2-BAS01	PR_FS	0
											G2-CONCEP	PR_FF	0
											G2-RISKMAN	PR_FS	0
G2-BAS01	SEND & ASSIGN GATE 3 PRELIMINARY BASELINE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	G2-RISKMAN	PR_SS	0
G2-ALS013	SITE EVALUATION	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL03	PR_SS	0
G2-PGAT	PRELIMINARY GEOTECH ASSESSMENT	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-ALL03	PR_FS	2
											G2-DEDCE01	PR_FS	2
G2-SCOPE	SCOPING MEETING	[redacted]	A	[redacted]	A	GEGR	UNAS	[redacted]	[redacted]	[redacted]	G2-ALL03	PR_FS	2

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:04 PM

Project Item: 2046607
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046607
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

											G2-CEDESMET	PR_FS	0
											G2-DEDCE01	PR_FS	2
G2-DEDCE02	CONCEPTUAL DESIGN PLAN DWG	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDCE01	PR_FS	0
											G2-SCOPE	PR_FS	2
G2-EECRL01	CONCEPTUAL PCA SHORT CIRCUIT STUDY	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-CEDESMET	PR_FS	2
											G2-SCOPE	PR_FS	2
ALS01	PROPERTY OWNER NOTIFICATION (NOT NEEDED)	[redacted]	A	[redacted]	A	JFWE	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	0
G3-GATE3	GATE 3 ENGINEERING PHASE	[redacted]	A	[redacted]	A	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_SS	0
PEGWO	WORK ORDER (CREATE / UNSUSPEND)	[redacted]	A	[redacted]	A	HLUN	SUBA	[redacted]	[redacted]	[redacted]	HPB01	PR_FS	5
REPE2	PRE-ENGINEERING MEETING	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	0		0
ALS02	FIELD ENGINEERING	[redacted]	A	[redacted]	A	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	0
G2-CESTRFDN	CONCEPTUAL CIVIL FOUNDATION REVIEW	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	G2-DEDCE02	PR_SS	0
											G2-PGAT	PR_FS	2
DEDRQN	REQUISITION PHYSICAL NON-STOCK MATERIAL	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED01	PR_SS	0
G2-CEOILCON	PRELIMINARY OIL CONTAINMENT ASSESSMENT	[redacted]	A	[redacted]	A	DRTH	CASH	[redacted]	[redacted]	[redacted]	G2-CESTRFDN	PR_SS	2
G2-EECRL02	CONCEPTUAL PCA RELAY STUDY	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECRL01	PR_FS	0
BAS01	SEND & ASSIGN COMMITTED BASELINE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
CULT01	CULTURAL RESOURCES ASSESSMENT	[redacted]	A	[redacted]	A	JJCA	KKOS	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
DED01	PHYSICAL ENGINEERING	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
EECSK	PROTECTION & CONTROL PACKAGE	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	10
ENVR01	ENVIRONMENTAL ASSESSMENT	[redacted]	A	[redacted]	A	JJCA	DMRI	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	5
											PEGWO	PR_FS	10
G2-EECEPOV	CONCEPTUAL P&C RELAY OVERVIEW	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECRL01	PR_FS	3
											G2-EECRL02	PR_SS	0
G4-GATE4	GATE 4 CONSTRUCTION PHASE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	FCS02	PR_SS	0
											GCS01	PR_SS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item:	2046607	Job ID:	2046607
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	5/30/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

											GCSEI02	PR_SS	0
											REPE3	PR_SS	0
GEOTECH	GEOTECH	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	ALS01	PR_FS	10
											PEGWO	PR_FS	0
REPE3	PRE-CONSTRUCTION MEETING	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	CULT01	PR_FS	0
											DED02	PR_FS	0
TSTT01	TELECOM REVIEW	[redacted]	A	[redacted]	A	INFO	ATHA	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	10
G2-DEDCIE	CIVIL ESTIMATING	[redacted]	A	[redacted]	A	RPRI	JEHE	[redacted]	[redacted]	[redacted]	G2-CEOILCON	PR_FS	0
											G2-CESTRFDN	PR_FS	0
G2-DEDTEAMS	UPDATE TEAMS MATERIAL AND LABOR- PHYISCAL	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-CEOILCON	PR_FS	0
											G2-CESTRFDN	PR_FS	0
											G2-DEDCE02	PR_FS	2
ALS03	OFFICE ENGINEERING	[redacted]	A	[redacted]	A	JFWE	WDKN	[redacted]	[redacted]	[redacted]	ALS02	PR_FS	0
ENVR01S	SUBSTATION SAMPLING	[redacted]	S	[redacted]	S	CCOL	NLHU	[redacted]	[redacted]	[redacted]	DED01	PR_SS	5
FCLNOI	STORMWATER PLAN NOI	[redacted]	S	[redacted]	S	GEGI	GEGI	[redacted]	[redacted]	[redacted]	ALS05	PR_FS	4
G2-EECEP01	CONCEPTUAL CONTROL DESIGN	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEPOV	PR_FS	0
											G2-EECRL02	PR_FS	0
											G2-SCOPE	PR_FS	2
FCS01	BID GRADING	[redacted]	S	[redacted]	S	MSMI		[redacted]	[redacted]	[redacted]	DED02	PR_FS	5
											REPE2	PR_FS	20
G2-DEDQAEST	QA PHYSICAL ESTIMATE	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDCIE	PR_FS	0
											G2-DEDTEAMS	PR_FS	0
ALS05	DESIGN GRADING	[redacted]	A	[redacted]	A	DRTH	NFDY	[redacted]	[redacted]	[redacted]	ALS03	PR_FS	0
											ENVR01	PR_FS	5
											REPE2	PR_FS	10
GTSWR	WORK REQUEST SUBMITTAL	[redacted]	A	[redacted]	A	DRSM	UNAS	[redacted]	[redacted]	[redacted]	REPE2	PR_FS	25

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046607
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046607
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

G2-EECEPQA	CONCEPTUAL CONTROL DESIGN REVIEW	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEP01	PR_FS	0
G2-DEDSFED	SHAREHOLDER FEEDBACK IMPLEMENTATION	[redacted]	A	[redacted]	A	RPRI	UNAS	[redacted]	[redacted]	[redacted]	G2-DEDQAEST	PR_FS	5
CECONTDE	OIL CONTAINMENT DESIGN ENGINEERING	[redacted]	A	[redacted]	A	DRTH	RFIS	[redacted]	[redacted]	[redacted]	CESTRFDN	PR_SS	0
CESTRFDN	CIVIL STRUCTURE REVIEW & FOUNDATION DESIGN	[redacted]	A	[redacted]	A	DRTH	GWAS	[redacted]	[redacted]	[redacted]	DED01	PR_SS	10
											GEOTECH	PR_FS	2
G2-EECEP02	CONCEPTUAL CONTROL DESIGN TRANSMITTAL	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEPQA	PR_FS	0
G2-EECTEAMS	UPDATE TEAMS MATERIAL AND LABOR - CONTROL	[redacted]	A	[redacted]	A	SHAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEPQA	PR_FS	0
GCW02	SHOP WIRING	[redacted]	S	[redacted]	S	BSMC	UNAS	[redacted]	[redacted]	[redacted]	EEC02	PR_FS	8
											EECRQN	PR_FS	20
G2-GTSRVW	CONCEPTUAL TEST REVIEW	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	G2-EECEP02	PR_FS	2
PEERVW	PEER REVIEW	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED01	PR_FS	0
EECSKQC	P&C QUALITY CONTROL	[redacted]	A	[redacted]	A	PCAS	UNAS	[redacted]	[redacted]	[redacted]	EECSK	PR_FS	5
DEDQA	PHYSICAL ENGINEERING QA	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	ALS05	PR_FS	0
											CECONTDE	PR_FS	0
											CESTRFDN	PR_FS	0
											DED01	PR_FS	0
											PEERVW	PR_FS	0
DED02	TRANSMIT PHYSICAL ENGINEERING	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	DEDQA	PR_FS	0
											G3-GATE3	PR_FF	0
DEDSF	SEND DRAWINGS TO SHOP FAB	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED02	PR_SS	0
EECPT	PRELIMINARY TRANSMITTAL	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECSKQC	PR_FS	1
EEC01	CONTROL ENGINEERING INDOOR	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	DED01	PR_SS	15
											EECPT	PR_FS	0
											EECSK	PR_FS	0
											EECSKQC	PR_FS	5
											TSTT01	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:04 PM

Project Item:	2046607	Job ID:	2046607
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	5/30/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

EECRQN	REQUISITION CONTROL NON-STOCK MATERIAL	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC01	PR_SS	5
EECQA	CONTROL ENGINEERING QA INDOOR	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC01	PR_FS	0
EEC02	TRANSMIT CONTROL ENGINEERING INDOOR	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECQA	PR_FS	0
											G3-GATE3	PR_FF	0
EECRL01	DESIGN RELAY SETTINGS	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EEC02	PR_FS	1
FCS02	SUBSTATION GRADING	[redacted]	S	[redacted]	S	MSMI	JERL	[redacted]	[redacted]	[redacted]	FCLNOI	PR_FS	4
											FCS01	PR_FS	16
EECRLQC	DESIGN RELAY SETTINGS QC	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EECRL01	PR_FS	0
GTSPQA	PANEL QUALITY ASSURANCE	[redacted]	A	[redacted]	A	TGUA	UNAS	[redacted]	[redacted]	[redacted]	GCW02	PR_FS	12.5
EQPT	MATERIALS LOE	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	MAJ_EQPT - S	PR_SS	0
MAJ_EQPT - S	RECEIVE MAJOR EQUIPMENT	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	PEGWO	PR_FS	5
SHIPPING	MATERIAL LONGEST LEAD ITEM	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEDRQN	PR_SS	5
											EQPT	PR_FF	0
EECRL02	TRANSMIT RELAY SETTINGS	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	EECRLQC	PR_FS	0
											G3-GATE3	PR_FF	0
GTSREV	TEST REVIEW	[redacted]	A	[redacted]	A	DRSM	UNAS	[redacted]	[redacted]	[redacted]	EEC02	PR_FS	10
											EECRL02	PR_FS	0
EEC03	TRANSMITTAL OF LOGIC DIAGRAM	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECRL02	PR_FS	1
											G3-GATE3	PR_FF	0
EEC11	CONTROL ENGINEERING OUTDOOR	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC01	PR_SS	0
											MAJ_EQPT - S	PR_FS	0
MCS01	RECEIVE MATERIAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DEDSF	PR_FS	0
											EQPT	PR_FF	0
											GCS01	PR_SS	-40
											SHIPPING	PR_FS	0

PUBLIC DISCLOSURE
GEORGIA POWER COMPANY

Job Network Report

Project Item:	2046607	Job ID:	2046607
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	5/30/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

GCS01	SUBSTATION CONSTRUCTION PRE-WORK ([redacted])	[redacted]	S	[redacted]	S	UNAS	UNAS	[redacted]	[redacted]	[redacted]	DED02	PR_FS	32
											DEDSF	PR_FS	38.4
											EEC02	PR_FS	24
											ENVR01S	PR_FS	12.8
											FCS02	PR_FS	5
											MAJ_EQPT - S	PR_FS	4
											REPE3	PR_FS	6.4
EECQAO	CONTROL ENGINEERING QA OUTDOOR	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EEC11	PR_FS	0
EEC12	TRANSMIT CONTROL ENGINEERING OUTDOOR	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECQAO	PR_FS	0
											G3-GATE3	PR_FF	0
EEGREV	REVIEW TEAMS ESTIMATE (LABOR/MATERIAL)	[redacted]	A	[redacted]	A	SEHI	SUBA	[redacted]	[redacted]	[redacted]	BAS01	PR_FS	0
											DED02	PR_FS	10
											EEC02	PR_FS	10
											EEC12	PR_FS	1
GCSCH	INSTALL CONTROL HOUSE (NOT NEEDED)	[redacted]	A	[redacted]	A	SCOT	UNAS	[redacted]	[redacted]	[redacted]	0		0
GCSEI02	INSTALL EQUIPMENT	[redacted]	S	[redacted]	S	JEWD	UNAS	[redacted]	[redacted]	[redacted]	GCS01	PR_SS	10
OUTAGE	SUB OUTAGE - CAPITAL	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	GCS01	PR_SS	0
GCW01	FIELD WIRING	[redacted]	S	[redacted]	S	BSMC	CCOL	[redacted]	[redacted]	[redacted]	GCS01	PR_SS	20
PHYSEC	PHYSICAL SECURITY INTEGRATOR	[redacted]	A	[redacted]	A	MCMA	MCMA	[redacted]	[redacted]	[redacted]	0		0
TSFT	SUB FIBER TERMINATION	[redacted]	A	[redacted]	A	INFO	JGCR	[redacted]	[redacted]	[redacted]	0		0
TSTT02	CIRCUIT INSTALLATION	[redacted]	A	[redacted]	A	INFO	ATHA	[redacted]	[redacted]	[redacted]	0		0
GTS01	TEST & CUT-IN (LOE)	[redacted]	S	[redacted]	S			[redacted]	[redacted]	[redacted]	GTS01-A1	PR_SS	0
GTS01-A1	TEST & CUT-IN (Engineer 1)	[redacted]	S	[redacted]	S	DRSM	UNAS	[redacted]	[redacted]	[redacted]	EEC03	PR_FS	0
											GCW01	PR_SS	0
											GTSPQA	PR_FS	6.25

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Date:03/11/2024
Time:02:23:04 PM

Project Item:	2046607	Job ID:	2046607
OP: FP:		Job Status:	APPROVED
Job Name:	EATONTON PRIMARY	Region:	CENTRAL
Job Desc:	BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br	Owner:	GPCO
Job Type:	MODIFICATION		
Area:	CENTRAL-MACON		
In Service Date:	5/30/2025 (Scheduled) Facility Required Date: 6/1/2025		
Project Manager:	[redacted]		

											GTSREV	PR_FS	10
											GTSWR	PR_FS	0
GTS01-A2	TEST & CUT-IN (Engineer 2)	[redacted]	S	[redacted]	S	DRSM	UNAS	[redacted]	[redacted]	[redacted]	EEC03	PR_FS	0
											GCW01	PR_SS	0
											GTS01	PR_FF	0
											GTSPQA	PR_FS	6.25
											GTSREV	PR_FS	10
											GTSWR	PR_FS	0
DED03	FINAL SUBSTATION INSPECTION	[redacted]	S	[redacted]	S	RACB	BPEP	[redacted]	[redacted]	[redacted]	GCS01	PR_FS	0
											GTS01-A1	PR_FF	-1
											GTS01-A2	PR_FF	-1
DEDAB	AS-BUILT PHYSICAL ENGINEERING	[redacted]	A	[redacted]	A	RACB	BPEP	[redacted]	[redacted]	[redacted]	DED03	PR_SS	0
G5-GATE5	GATE 5 CLOSEOUT PHASE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	HPB02	PR_SS	0
HPB02	REQUIRED FINISH / IN-SERVICE DATE	[redacted]	S	[redacted]	S	HLUN	ANAL	[redacted]	[redacted]	[redacted]	DED03	PR_FF	0
											DESC	PR_FF	0
											FCS02	PR_FS	0
											G4-GATE4	PR_FF	0
											GCS01	PR_FS	0
											GCSEI02	PR_FS	0
											GCW01	PR_FS	0
											GTS01-A1	PR_FS	0
											GTS01-A2	PR_FS	0
											GTSFC	PR_FS	0
											MCS01	PR_FS	0
											OUTAGE	PR_FS	0
											REPE3	PR_FS	0

PUBLIC DISCLOSURE

GEORGIA POWER COMPANY

Job Network Report

Project Item: 2046607
OP: FP:
Job Name: EATONTON PRIMARY
Job Desc: BCA Approved 11/15/23 Installation of Smart Valve devices in the Eatonton and Br
Job Type: MODIFICATION
Area: CENTRAL-MACON
In Service Date: 5/30/2025 (Scheduled) Facility Required Date: 6/1/2025
Project Manager: [redacted]

Job ID: 2046607
Job Status: APPROVED
Region: CENTRAL
Owner: GPCO

GTSFC	TEST FIELD CHANGES	[redacted]	S	[redacted]	S	DRSM	UNAS	[redacted]	[redacted]	[redacted]	GTS01-A1	PR_FS	0
											GTS01-A2	PR_FS	0
EECRL03	PROMOTE PENDING RELAY SETTINGS	[redacted]	A	[redacted]	A	UNAS	UNAS	[redacted]	[redacted]	[redacted]	GTS01-A1	PR_FS	10
											GTS01-A2	PR_FS	5
											HPB02	PR_FS	0
EECAB	AS-BUILT CONTROL ENGINEERING	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	GTSFC	PR_FS	5
EECFCR	CONTROL ENGINEERING FIELD CHANGE REVIEW	[redacted]	A	[redacted]	A	RACB	X2BP	[redacted]	[redacted]	[redacted]	EECAB	PR_SS	10
WKOC	WORK ORDER CLOSE	[redacted]	A	[redacted]	A	SEHI	SUBA	[redacted]	[redacted]	[redacted]	DEDAB	PR_FS	0
											DESC	PR_FF	0
											EECAB	PR_FS	0
											EECFCR	PR_FS	0
											EECRL03	PR_FS	0
											G5-GATE5	PR_FF	0
											HPB02	PR_FS	60

*** End of Report ***

PUBLIC DISCLOSURE

Project Item: 2046601

OP: 11073222 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

Description:

OPTION 1: Installing Smart Valve Just Outside the existing fence - Northwest side see attachment to this PI. Installation of Smart Valve devices at Eatonton Primary on the Eatonton Primary-Oasis 230kV line and the Branch - Oasis 230kV line.

This PI covers (intends to capture) Smart Valve material and GPC construction labor only.

All other costs will be captured on PI 2046607.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
CURRENT LIMITING REACTOR	EA	2	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT ADDITIONS			[redacted]			
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS				[redacted]		
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS			[redacted]			
PLANT REMOVALS						
Sub-Total PLANT REMOVALS				[redacted]		
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS				[redacted]		
TOTAL PLANT REMOVALS WITHOUT OVERHEADS					[redacted]	
MAINTENANCE						
Sub-Total MAINTENANCE				[redacted]		
TOTAL MAINTENANCE				[redacted]		

PUBLIC DISCLOSURE

Project Item: 2046601

OP: 11073222 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Additions	[redacted]
Plant Removals (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Removals	[redacted]
Plant Salvage	[redacted]
Total PI CIAC	[redacted]
Total Cash Required	[redacted]
Total Maintenance Cost	[redacted]
Original Cost Retired	[redacted]

*** End of Report ***

PUBLIC DISCLOSURE

 ESTIMATED COST BY RETIREMENT UNITS Time: 02:23:07PM

Project Item: 2046604

OP: 11073729 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY - OASIS 230KV Facility Required Date: 6/1/2025

Nearest Town: Originator: [redacted]

Description:

GPC LINE WORK:

Line modifications to first outside the northwest side of substation: Between substation structure and structrue 42.

1/22/2024 ROF Note: Estimate most conservative scenario to be able to cover the highest potential cost associate with this work.

Summary of Scope of Work:
Line modifications to first outside the northwest side of substation: Between substation structure and structure 42.
Segment: SW 190231 EATONTON (42) - STR (89)
Structure 42: (2) Lattice Steel 100 feet high; Martin 1361.5 54/19 ASCR Conductor
- (3) Brown Disc Insulators 16 Disc per String; (12) Steel Galvanized 7/16" Guys, (12) 2 Helix Anchors; Grounding # 2CU

*** Estimators comments are located in the "Estimate Notes" tab ***

****************PCA NOTES - [redacted] 02/13/2024****************

- Update Eatonton Primary-Oasis 230kV TLD as necessary.

***************END PCA NOTES*****************

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
GROUNDING-COUNTERPOISE	FT	254	[redacted]			
GROUNDING-STANDARD GROUND GAL	EA	3	[redacted]			
GUYS, FIXTURES AND GUYS	LT	1	[redacted]			
INSULATOR-SUSPENSION 230KV	SE	1	[redacted]			
INSUL-HORIZONTAL POST 230KV	SE	1	[redacted]			
SET OF FIXTURES	EA	12	[redacted]			
STEEL POLE - 100'	EA	3	[redacted]			
TRANS, MEALS, ETC.	LT	1	[redacted]			
WIRE-ACSR,SINGLE CONDUCTOR	LT	1	[redacted]			
WIRE-ACSS 1 COND 1351.5 KCMIL	FT	1,950	[redacted]			
WIRE-ALUMOWELD (OH GND	LT	1	[redacted]			
WIRE-STEEL (OH GRND 3/8"	FT	650	[redacted]			
Discipline Total			[redacted]			
ENGINEERING(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
RIGHT OF WAY(Estimator: [redacted])						
ROW:CREW SUPPORT	LT	1	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT ADDITIONS			[redacted]			
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS			[redacted]			
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS			[redacted]			
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						

 ESTIMATED COST BY RETIREMENT UNITS

Project Item: 2046604

OP: 11073729 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY - OASIS 230KV Facility Required Date: 6/1/2025

Nearest Town: Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
ANCHOR GUY	EA	4	[redacted]			
ARM-STEEL TUBULAR CROSSARM	EA	1	[redacted]			
GROUNDING-COUNTERPOISE	FT	254	[redacted]			
GROUNDING-STANDARD GROUND GAL	EA	2	[redacted]			
INSULATOR-SUSPENSION 230KV	SE	1	[redacted]			
STEEL POLE - 100'	EA	2	[redacted]			
WIRE-ACSR,SGL COND 1351 KCMIL	FT	1,950	[redacted]			
WIRE-ALUMOWELD (OH GRND 7#9	FT	650	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT REMOVALS			[redacted]			
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS			[redacted]			
TOTAL PLANT REMOVALS WITHOUT OVERHEADS				[redacted]		
MAINTENANCE						
Sub-Total MAINTENANCE			[redacted]			
TOTAL MAINTENANCE			[redacted]			

PUBLIC DISCLOSURE

Project Item: 2046604

OP: 11073729 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY - OASIS 230KV Facility Required Date: 6/1/2025

Nearest Town: Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Additions	[redacted]
Plant Removals (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Removals	[redacted]
Plant Salvage	[redacted]
Total PI CIAC	[redacted]
Total Cash Required	[redacted]
Total Maintenance Cost	[redacted]
Original Cost Retired	[redacted]

*** End of Report ***

PUBLIC DISCLOSURE

Project Item: 2046605

OP: 11073730 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: BRANCH - OASIS 230KV Facility Required Date: 6/1/2025

Nearest Town: Originator: [redacted]

Description:

GPC LINE WORK:

Line modifications to first outside the northwest side of substation: Between substation structure and structrue 42.

1/22/2024 ROF Note: Estimate most conservative scenario to be able to cover the highest potential cost associate with this work.

Summary of Scope of Work:
Line modifications to first outside the northwest side of substation: Between substation structure and structure 42.
Segment: SW 190319 EATONTON PRIMARY (42) - STR 89
Structure 42: (2) Lattice Steel 100 feet high; Martin 1361.5 54/19 ASCR Conductor
- (3) Brown Disc Insulators 16 Disc per String; (12) Steel Galvanized 7/16" Guys, (12) 2 Helix Anchors; Grounding # 2CU

*** Estimators comments are located in the "Estimate Notes" tab.***

****************PCA NOTES - [redacted] 02/13/2024****************

- Update Branch-Oasis 230kV line TLD as necessary.

***************END PCA NOTES*****************

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
GROUNDING-COUNTERPOISE	FT	254	[redacted]			
GROUNDING-STANDARD GROUND GAL	EA	3	[redacted]			
GUYS, FIXTURES AND GUYS	LT	1	[redacted]			
INSULATOR-SUSPENSION 230KV	SE	1	[redacted]			
INSUL-HORIZONTAL POST 230KV	SE	1	[redacted]			
SET OF FIXTURES	EA	12	[redacted]			
STEEL POLE - 100'	EA	3	[redacted]			
TRANS, MEALS, ETC.	LT	1	[redacted]			
WIRE-ACSR,SINGLE CONDUCTOR	LT	1	[redacted]			
WIRE-ACSS 1 COND 1351.5 KCMIL	FT	1,950	[redacted]			
WIRE-ALUMOWELD (OH GND	LT	1	[redacted]			
WIRE-STEEL (OH GRND 3/8"	FT	650	[redacted]			
Discipline Total			[redacted]			
ENGINEERING(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
RIGHT OF WAY(Estimator: [redacted])						
ROW:CREW SUPPORT	LT	1	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT ADDITIONS			[redacted]			
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS			[redacted]			
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS			[redacted]			
PLANT REMOVALS						

PUBLIC DISCLOSURE

Project Item: 2046605

OP: 11073730 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: BRANCH - OASIS 230KV Facility Required Date: 6/1/2025

Nearest Town: Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	4	[redacted]			
ARM-STEEL TUBULAR CROSSARM	EA	1	[redacted]			
GROUNDING-COUNTERPOISE	FT	254	[redacted]			
GROUNDING-STANDARD GROUND GAL	EA	2	[redacted]			
INSULATOR-SUSPENSION 230KV	SE	1	[redacted]			
STEEL POLE - 100'	EA	2	[redacted]			
WIRE-ACSR,SGL COND 1351 KCMIL	FT	1,950	[redacted]			
WIRE-ALUMOWELD (OH GRND 7#9	FT	650	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT REMOVALS			[redacted]			
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS			[redacted]			
TOTAL PLANT REMOVALS WITHOUT OVERHEADS				[redacted]		
MAINTENANCE						
Sub-Total MAINTENANCE			[redacted]			
TOTAL MAINTENANCE			[redacted]			

Project Item: 2046605

OP: 11073730 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: BRANCH - OASIS 230KV Facility Required Date: 6/1/2025

Nearest Town: Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Additions	[redacted]
Plant Removals (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Removals	[redacted]
Plant Salvage	[redacted]
Total PI CIAC	[redacted]
Total Cash Required	[redacted]
Total Maintenance Cost	[redacted]
Original Cost Retired	[redacted]

*** End of Report ***

PUBLIC DISCLOSURE

ESTIMATED COST BY RETIREMENT UNITS

Time: 02:23:10PM

Project Item: 2046606

OP: 11073731 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

Description:

GPC LINE WORK: Needed for Option 1.

Line modifications between structures 1A,1 and 2 to acommodate the installation of Smart Valve on the 230kV lines just outside the Eatonton Primary station.

1/22/2024 ROF Note: Estimate most conservative scenario to be able to cover the highest potential cost associate with this work.

Summary of Scope of Work:
Line modifications between structures 1A and 2 to accommodate the installation of Smart Valve on the 230kV lines just outside the Eatonton Primary station.

Segment 3: SW 190319 EATONTON PRIMARY (42) - STR 89; Penguin 4/0 ACSR w/ 6/1 Stranding; 5/16" Galvanized Steel Shield Wire
- Structure 2: 65'/Class H1S Concrete Pole; (3) 69kV Polymer Post Insulators & (5) 20K. 10" Porcelain Disc w/ 7 Disc per String Insulators; 7#10 CW Driven Rod Grounding; (6) ½" Galvanized Steel w/ 7 Stranding Guy Wires; (4) 2 Helix Anchors; (6) Fiberglass w/ 54 Length and 50000 Strength Guy Insulators.

Segment 2: EATONTON JCT (1) - SW 190401 N.O. EATONTON; Linnet 336.4 w/ 26/7 Stranding ACSR; 5/16" Galvanized Steel Shield Wire
- Structure 2: 40'/Class 4 Wood Pole; (6) Brown Disc Insulators w/ 5 disc per string; 7#10 CW Driven Rod Grounding; (3) 3/8" Galvanized Steel Guy Wires w. 7 Stranding; (3) Expanding Guy Anchors; (1) Fiberglass ACME Guy Insulator w/ 35 Length and 21000 Strength; (2) Fiberglass ACME Guy Insulator w/ 54 Length and 21000 Strength

Segment 1: SW 190443 EATONTON - EATONTON JCT; Linnet 336.4 w/ 26/7 Stranding ACSR; 5/16" Galvanized Steel Shield Wire
- Structure 1: 60'/Class 2 Wood Pole; (2) 7/16" Galvanized Steel Guys; (2) Single Helix Anchors; (2) Fiberglass ACME Electric 54 Length w/ 21000 Strength Guy Insulators;
- Structure 1A: 45'/Class 3 Wood Pole (6) Polymer 46kV Strain w/ 1 disc per string & (3) Polymer Post 46kV w/ disc per string; 2) 7/16" Galvanized Steel Guys; (1) 2 Helix Anchors; (2) Fiberglass ACME Electric 54 Length w/ 21000 Strength Guy Insulators;

Estimate Assumptions:
Remove
- 720' Transmission Conductors and OHGW
- Structure 1A, 1, 2, & 2
Install
- 720' transmission conductors and OHGW
- Structure 2 Segment 3: 45'/LC7 Concrete Pole; 3-Way Deadend; (3WECB3; BT-.038.1)
- Structure 2A: 45'/LC7 Concrete Pole; One Pole Double String, Type 3 Large Angle Structure (1CDS3; BT-020.1)
- Structure 1: 45'/LC7 Concrete Pole; One Pole Double String, Type 2 Medium Angle Structure (1SCSP2; BT-018.1)
- Structure 1A: 45'/LC7 Concrete Pole; One Pole Double String, Type 2 Medium Angle Structure (1SCSP2; BT-018.1)
- Structure 2 Segment 2: 40/LC7 Concrete Pole; One Pole Double String, Type 2 Medium Angle Structure (1SCSP2; BT-018.1)

Labor Estimates
Engineering
- Pre-Engineering - [redacted] Hours
- Preliminary Engineering - [redacted] Hours
- Field Activity - Engineering - [redacted] Hours
- Eng/Design - [redacted] Hours
Construction
- Labor - [redacted] weeks @ [redacted] days per week ([redacted] on 2/8/24)
Construction Support
- ROW Clearing - N/A
- Crew Support - 10 units @ $[redacted] = $[redacted] Total
? [redacted] weeks @ $[redacted] per Week
- Civil - Final pole locations, classes, and work sequences to be coordinated with civil site plan and final grade for smart valve installation.

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	44	[redacted]			
FIXTURES & GUYS (UNDER 110)	LT	1	[redacted]			

PUBLIC DISCLOSURE

TMCRET40 GEORGIA POWER COMPANY Date: 03/11/2024

 ESTIMATED COST BY RETIREMENT UNITS Time: 02:23:10PM

Project Item: 2046606

OP: 11073731 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
GROUNDING-DRIVEN RODS	EA	7	[redacted]			
GROUNDING-STANDARD GROUND GAL	EA	7	[redacted]			
INSULATORS-SUSPENSION	LT	1	[redacted]			
INSULATOR-SUSPENSION 46KV	SE	7	[redacted]			
INSUL-HORIZONTAL POST 46KV	SE	3	[redacted]			
POLES-CONCRETE - 40 FT.	EA	1	[redacted]			
POLES-CONCRETE - 45 FT.	EA	4	[redacted]			
WIRE-ACSR,SGL COND 336.4KCMIL	FT	2,250	[redacted]			
WIRE-STEEL (OH GRND 3/8"	FT	750	[redacted]			
WIRE-STEEL(OH GND	LT	1	[redacted]			
Discipline Total			[redacted]			
ENGINEERING(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
RIGHT OF WAY(Estimator: [redacted])						
ROW:CREW SUPPORT	LT	1	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT ADDITIONS			[redacted]			
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS			[redacted]			
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS			[redacted]			
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
ANCHOR GUY	EA	4	[redacted]			
FIXTURES & GUYS (UNDER 110)	LT	1	[redacted]			
GROUNDING-DRIVEN RODS	EA	2	[redacted]			
GROUNDING-STANDARD GROUND GAL	EA	2	[redacted]			
INSULATORS-SUSPENSION	LT	1	[redacted]			
INSULATOR-SUSPENSION 46KV	SE	2	[redacted]			
INSUL-HORIZONTAL POST 46KV	SE	1	[redacted]			
POLES-CONCRETE - 65 FT.	EA	1	[redacted]			
POLES-WOOD - 40 FT.	EA	1	[redacted]			
POLES-WOOD - 45 FT.	EA	1	[redacted]			
POLES-WOOD - 60 FT.	EA	1	[redacted]			
WIRE-ACSR,SGL COND 336.4KCMIL	FT	1,350	[redacted]			
WIRE-ACSR,SGL COND 4/0	FT	400	[redacted]			
WIRE-STEEL (OH GRND 5/16"	FT	750	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT REMOVALS			[redacted]			
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS			[redacted]			
TOTAL PLANT REMOVALS WITHOUT OVERHEADS			[redacted]			
MAINTENANCE						

PUBLIC DISCLOSURE

Project Item: 2046606

OP: 11073731 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
Sub-Total MAINTENANCE			[redacted]			
TOTAL MAINTENANCE			[redacted]			

TMCRET40 GEORGIA POWER COMPANY Date: 03/11/2024

 ESTIMATED COST BY RETIREMENT UNITS Time: 02:23:10PM

Project Item: 2046606

OP: 11073731 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY 190442 - RAYONIER 46 KV Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Additions	[redacted]
Plant Removals (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Removals	[redacted]
Plant Salvage	[redacted]
Total PI CIAC	[redacted]
Total Cash Required	[redacted]
Total Maintenance Cost	[redacted]
Original Cost Retired	[redacted]

*** End of Report ***

PUBLIC DISCLOSURE

ESTIMATED COST BY RETIREMENT UNITS Time: 02:23:13PM

Project Item: 2046607

OP: 11079740 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

Description:

OPTION 1: Installing Smart Valve Just Outside the existing fence - Northwest side see attachment to this PI. Installation of Smart Valve devices at Eatonton Primary on the Eatonton Primary-Oasis 230kV line and the Branch - Oasis 230kV line.

This PI covers (intends to capture) SoCo/GPC efforts related to the project. Smart Valve material and labor has been captured on PI 2046601.

Additional Scope (1/31/24): Install traps and tuners on either side of the Smart Valves devices for both 230kV lines.

****************PCA NOTES - [redacted] 02/13/2024****************

Oasis 230kV Line:
- Update relay settings for new Smart Valve. Increase Zone 2 to cover entire line impedance with full Smart Valve impedance.

***************END PCA NOTES*****************

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
PLANT ADDITIONS						
CONSTRUCTION(Estimator: [redacted])						
BUSWORK-BAR AND ANGLE, ALUM	FT	16	[redacted]			
BUSWORK-CABLE, ALUMINUM	FT	908	[redacted]			
BUSWORK-TUBE, ALUMINUM	FT	120	[redacted]			
CABINET, DC	EA	4	[redacted]			
CONDUIT-PLASTIC (PVC)	FT	1,080	[redacted]			
CONDUIT-STEEL	FT	40	[redacted]			
CONTROL CABLE	FT	1,350	[redacted]			
CONTROL HOUSE FOUNDATION	EA	12	[redacted]			
CONTROL SYSTEM ACCESSORIES	LT	1	[redacted]			
COUPLING CAPACITOR	EA	4	[redacted]			
FENCE, SUBSTATION AREA	FT	500	[redacted]			
FIBER OPTIC CABLE, CONT. RUN	EA	1,560	[redacted]			
FIBER OPTIC EQUIPMENT	LT	1	[redacted]			
FOUNDATION - HIGH VOLTAGE	EA	8	[redacted]			
INSULATOR-POST 230 KV	EA	4	[redacted]			
LINE TRAP	EA	4	[redacted]			
LINE TUNER	EA	4	[redacted]			
MISC AND CONTINGENCIES	LT	1	[redacted]			
MOVE ON/OFF JOB	LT	1	[redacted]			
OVERHEAD GROUND SYSTEM	LT	1	[redacted]			
PANEL / CABINET	EA	1	[redacted]			
SITE GROUNDING	LT	1	[redacted]			
SITE IMPROVEMENTS ACCESSORIES	LT	1	[redacted]			
SPECIAL SERVICES	LT	1	[redacted]			
STR-STEEL, HV, SECT,BAY,SUPP	EA	4	[redacted]			
STRUCTURE-LV (BELOW 69KV) ACC	LT	1	[redacted]			
SURFACING (STONE)	TN	2	[redacted]			
TRANS, MEALS, ETC.	LT	1	[redacted]			
Discipline Total			[redacted]			
ENGINEERING(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			

PUBLIC DISCLOSURE

TMCRET40 GEORGIA POWER COMPANY Date: 03/11/2024

 ESTIMATED COST BY RETIREMENT UNITS Time: 02:23:13PM

Project Item: 2046607

OP: 11079740 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
Discipline Total			[redacted]			
PLAN & PROJ(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
RIGHT OF WAY(Estimator: [redacted])						
CLEARING & GRUBBING	LT	1	[redacted]			
CLEARING & GRUBBING, INITIAL SITE PREP, ALL	LT	1	[redacted]			
DEMOLITION, INITIAL SITE PREP	LT	1	[redacted]			
DIRECT ENGINEERING	LT	1	[redacted]			
PILINGS	LT	1	[redacted]			
RETAINING WALL, COMPLETE	LT	1	[redacted]			
RETAINING WALLS	LT	1	[redacted]			
SURFACING (STONE)	TN	751	[redacted]			
Discipline Total			[redacted]			
TEST(Estimator: [redacted])						
DIRECT ENGINEERING	LT	1	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT ADDITIONS			[redacted]			
PLANT TRANSFER ADDITIONS						
Sub-Total PLANT TRANSFER ADDITIONS			[redacted]			
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS			[redacted]			
PLANT REMOVALS						
CONSTRUCTION(Estimator: [redacted])						
BUSWORK, ACCESSORIES	LT	1	[redacted]			
CONTROL CABLE	FT	10	[redacted]			
FENCE, SUBSTATION AREA	FT	265	[redacted]			
SITE GROUNDING	LT	1	[redacted]			
SITE IMPROVEMENTS ACCESSORIES	LT	1	[redacted]			
Discipline Total			[redacted]			
Sub-Total PLANT REMOVALS			[redacted]			
PLANT TRANSFER REMOVALS						
Sub-Total PLANT TRANSFER REMOVALS			[redacted]			
TOTAL PLANT REMOVALS WITHOUT OVERHEADS				[redacted]		
MAINTENANCE						
CONSTRUCTION(Estimator: [redacted])						
SITE IMPROVEMENTS ACCESSORIES	LT	1	[redacted]			
Discipline Total			[redacted]			
Sub-Total MAINTENANCE			[redacted]			
TOTAL MAINTENANCE			[redacted]			

PUBLIC DISCLOSURE

 ESTIMATED COST BY RETIREMENT UNITS Time: 02:23:13PM

Project Item: 2046607

OP: 11079740 FP: 11073072 Version: Budget From Working Copy

Type Work: MODIFICATION

Facility Name: EATONTON PRIMARY Facility Required Date: 6/1/2025

Nearest Town: EATONTON Originator: [redacted]

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Additions	[redacted]
Plant Removals (Labor, Matl, Eqp)	[redacted]
Overheads	[redacted]
Total Plant Removals	[redacted]
Plant Salvage	[redacted]
Total PI CIAC	[redacted]
Total Cash Required	[redacted]
Total Maintenance Cost	[redacted]
Original Cost Retired	[redacted]

*** 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 2024 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 worst contingency, case type and unity 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. These case types are described more fully in Section D1, 2024 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 an operating guide, a project (both preferred and alternative), 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 und the Code of Federal Regulations, Section 388.113. Therefore, these reports are redacted in their entirety in the Public Disclosure version of the IRP filing.

[H1a]

THERMAL PROBLEMS
&
SOLUTIONS

PUBLIC DISCLOSURE

2025-2034 TP-East Thermal Problems – v1C (DSHOT) Pages 1-74 are redacted in their entirety.

2025-2034 TP-East Thermal Problems – v1C (W) Pages 1-16 are redacted in their entirety.

2025-2034 TP-East Thermal Problems – v2B Pre-Layers (DSHOT) Pages 1-80 are redacted in their entirety.

2025-2034 TP-East Thermal Problems – v2B Post-Layers (DSHOT) Pages 1-58 are redacted in their entirety.

2025-2034 TP-East Thermal Problems – v2B Pre-Layers(W) Pages 1-9 are redacted in their entirety.

2025-2034 TP-East Thermal Problems – v2B Post-Layers(W) Pages 1-8 are redacted in their entirety.

[H1b]

VOLTAGE PROBLEMS
&
SOLUTIONS

PUBLIC DISCLOSURE

2025-2034 TP-East Voltage Problems – v1C (DHOST) Pages 1-11 are redacted in their entirety.

2025-2034 TP-East Voltage Problems – v1C (W) Pages 1-9 are redacted in their entirety.

2025-2034 TP-East Voltage Problems – v2B Pre-Layers (DHOST) Pages 1-14 are redacted in their entirety.

2025-2034 TP-East Voltage Problems – v2B Post-Layers (DHOST) Pages 1-5 are redacted in their entirety.

2025-2034 TP-East Voltage Problems – v2B Pre-Layers(W) Pages 1-15 are redacted in their entirety.

2025-2034 TP-East Voltage Problems – v2B Post-Layers(W) Pages 1-15 are redacted in their entirety.

[H2]

LOAD FLOW DATA FILES

LOAD FLOW FILES
“REDACTED”

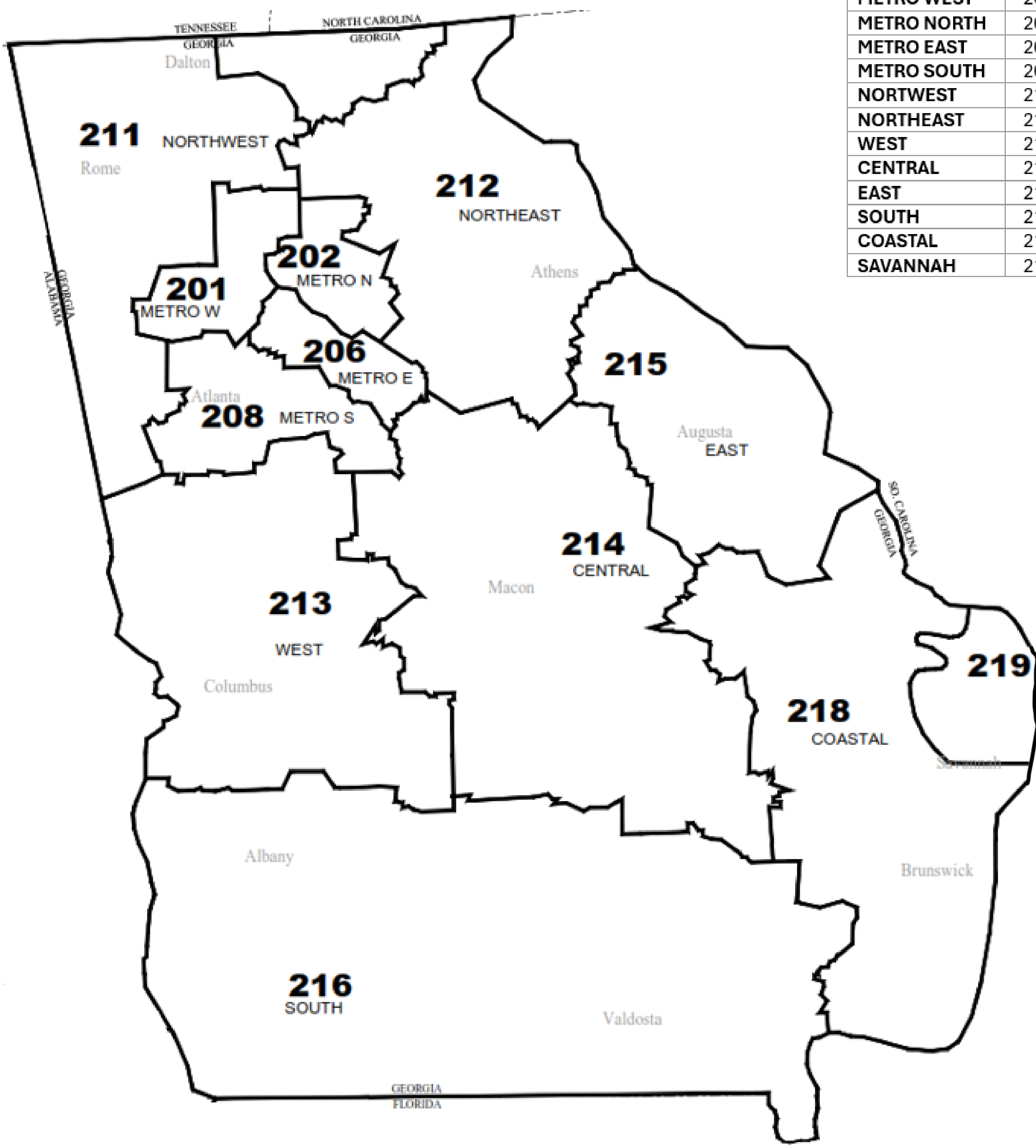
[H3]

ITS MAPS

PUBLIC DISCLOSURE

GEORGIA POWER REGION BOUNDARIES

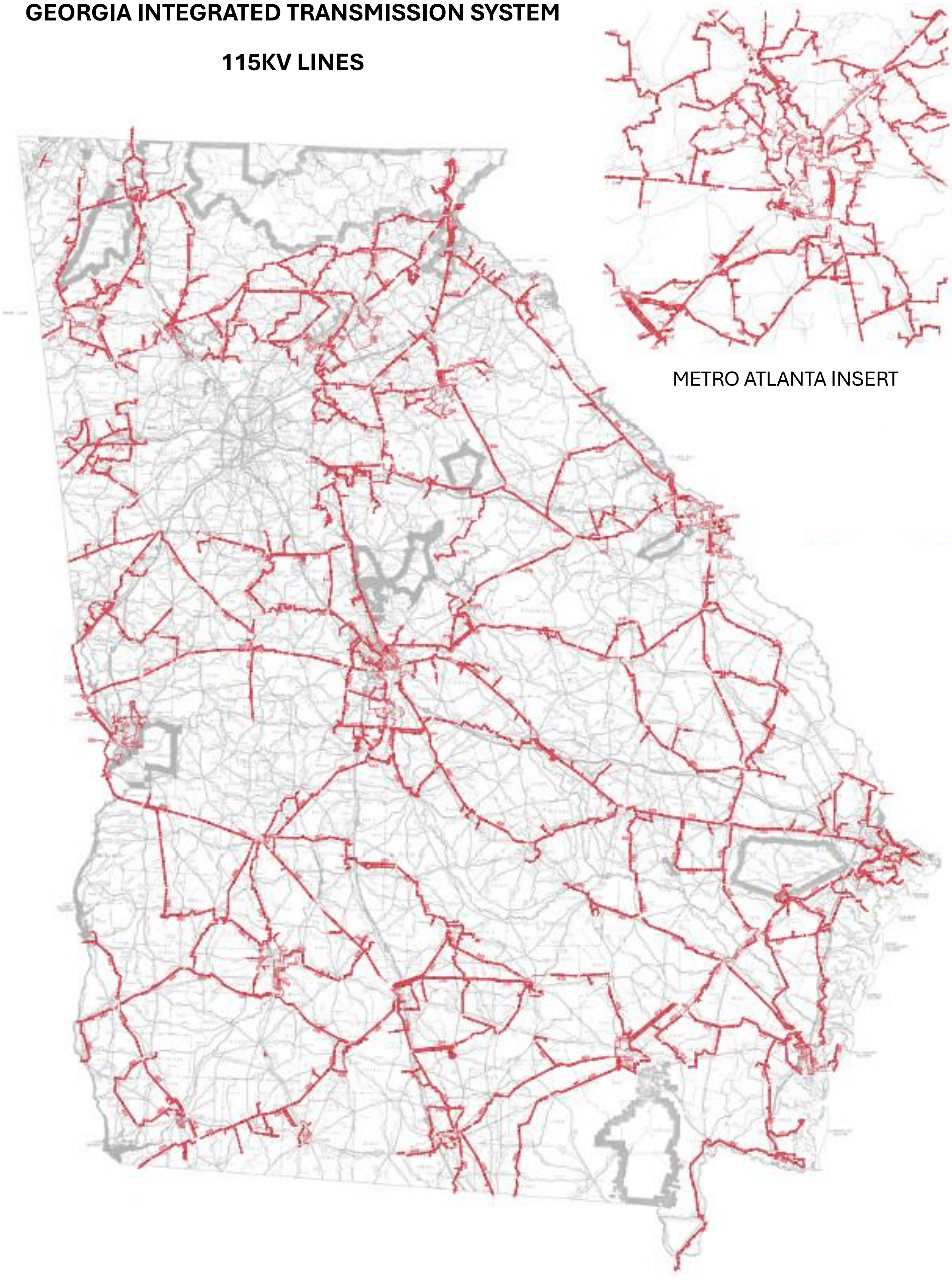
REGION	ZONE
METRO WEST	201
METRO NORTH	202
METRO EAST	206
METRO SOUTH	208
NORTWEST	211
NORTHEAST	212
WEST	213
CENTRAL	214
EAST	215
SOUTH	216
COASTAL	218
SAVANNAH	219



PUBLIC DISCLOSURE

GEORGIA INTEGRATED TRANSMISSION SYSTEM

115KV LINES

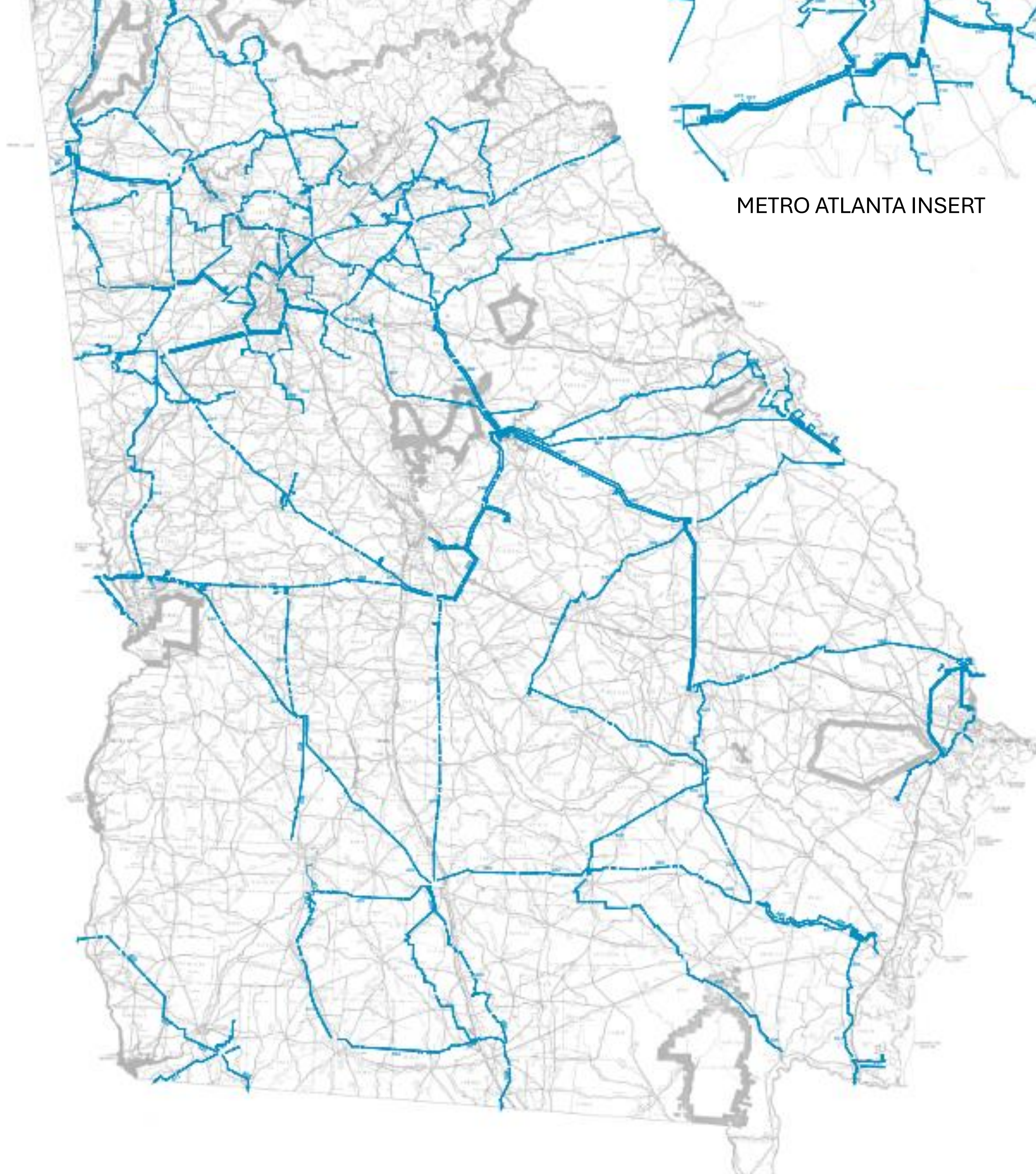


METRO ATLANTA INSERT

PUBLIC DISCLOSURE

GEORGIA INTEGRATED TRANSMISSION SYSTEM

230KV LINES

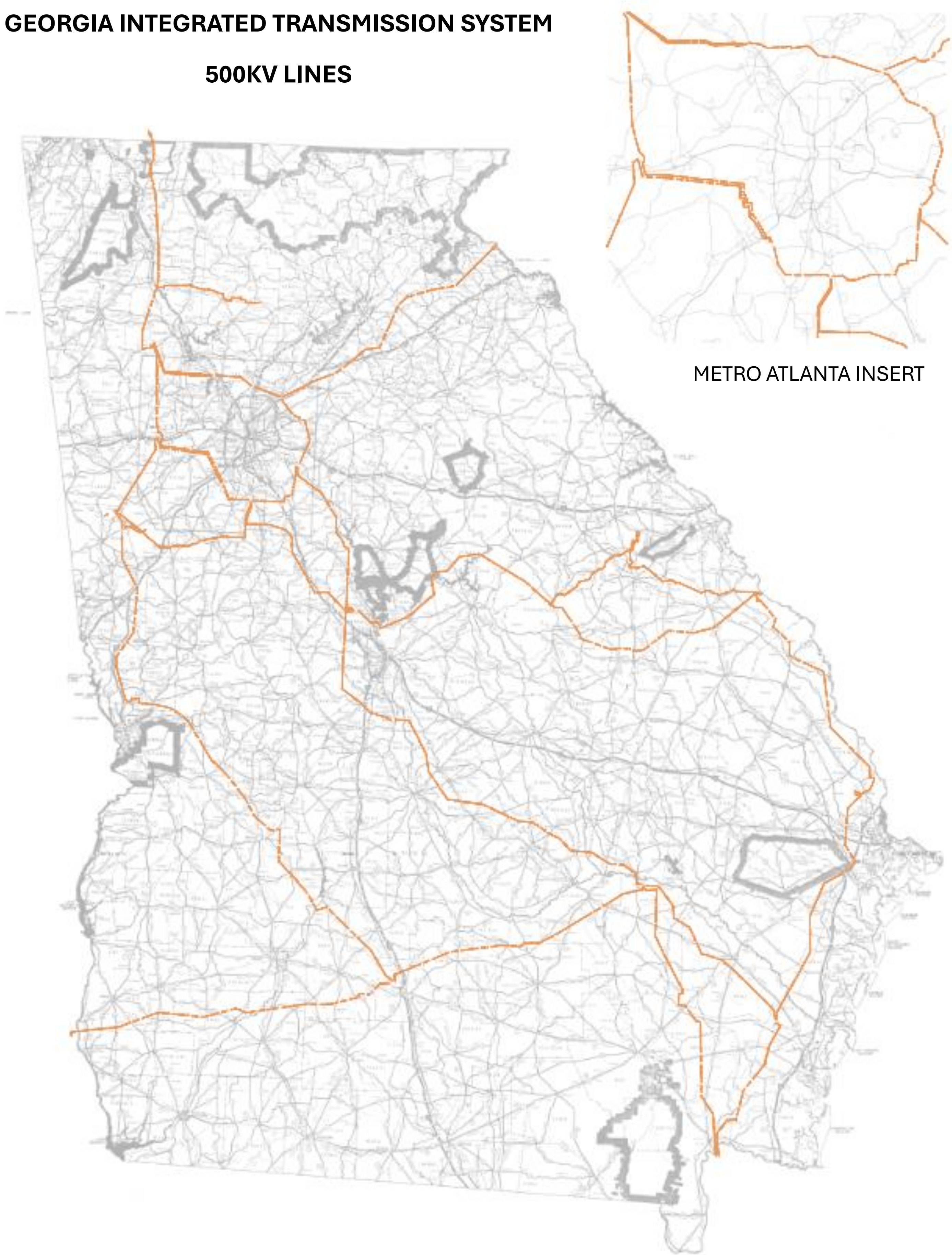


METRO ATLANTA INSERT

PUBLIC DISCLOSURE

GEORGIA INTEGRATED TRANSMISSION SYSTEM

500KV LINES



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ACRONYMS, ABBREVIATIONS & TECHNICAL DEFINITIONS

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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) and member of MISO RTO

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

GETs – Grid-Enhancing Technologies

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

LTWG – SERC Long – Term Working Group

MEAG – Municipal Electric Authority of Georgia, Georgia ITS Participant

MISO – Midcontinent Independent System Operator. When discussed in terms of the SBAA interface, MISO refers to the interconnections with Entergy and Cooperative Energy.

MMWG – Multi-regional Modeling Working Group functions under ERAG and is the NERC designee to develop Eastern Interconnection-wide power flow models per the MOD-032 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

RTO – Regional Transmission Organization

SAV – Savannah area transmission network

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 (also known as Santee Cooper)

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

Southern Companies – The Electric, Natural Gas, and other Companies that are under the umbrella of Southern Company; including but not limited to Georgia Power, Alabama Power, and Mississippi Power

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 SBAA interface, VACAR refers to the interconnections with Duke, DESC and SCPSA.

<u>Technical Definitions:</u>

Alternative Transmission Technologies – these technologies comprise a suite of tools that optimize the capacity, efficiency, and reliability of the existing electric grid. By leveraging advanced materials, and power electronics, these tools enhance transmission performance without extensive new infrastructure. They are essential for addressing transmission constraints, improving operational flexibility, and supporting clean energy integration. These technologies include the following:

- Static Synchronous Compensators
- Static VAR Compensators
- Advanced Power Flow Control Devices
- Transmission Switching
- Synchronous Condensers
- Voltage Source Converters
- Advanced Conductors
- Tower Lifting

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