

PUBLIC DISCLOSURE

August 31, 2017

Mr. Reece McAlister
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SE, First Floor
Atlanta, Georgia 30334-5701

RE: Georgia Power Company's Seventeenth Semi-Annual Construction
Monitoring Report for Plant Vogtle Units 3 and 4; Docket No. 29849

Dear Mr. McAlister:

Enclosed for filing is Georgia Power Company's Seventeenth Semi-Annual Construction Monitoring Report for Plant Vogtle Units 3 and 4 pursuant to O.C.G.A. § 46-3A-7(b), Georgia Public Service Commission's ("Commission") Rule 515-3-4-.07(2)(b), and the Commission's Final Order in Docket No. 27800.

This information is being filed under the Trade Secret rules of the Commission.

Should you have any questions please feel free to call me at (404) 506-3050 or Richard White at 404-506-2393.

Sincerely,



Kyle Leach
Vice President, Regulatory Affairs
kcleach@southernco.com

Enclosure

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY'S)
SEVENTEENTH SEMI-ANNUAL)
CONSTRUCTION MONITORING)
REPORT CONCERNING)
ITS PARTICIPATION IN PLANT)
VOGTLE UNITS 3 AND 4)**

Docket No. 29849

**GEORGIA POWER COMPANY'S SEVENTEENTH SEMI-ANNUAL CONSTRUCTION
MONITORING REPORT, REQUEST FOR APPROVAL OF THE EXPENDITURES
MADE BETWEEN JANUARY 1, 2017 AND JUNE 30, 2017, AND REQUEST FOR
APPROVAL OF THE REVISED PROJECT COST ESTIMATES AND CONSTRUCTION
SCHEDULE PURSUANT TO O.C.G.A. § 46-3A-7(b)**

**SUBMITTED BY
GEORGIA POWER COMPANY
AUGUST 31, 2017**

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11. Bechtel Cost & Schedule Assessment

GEORGIA POWER COMPANY’S SEVENTEENTH SEMI-ANNUAL CONSTRUCTION MONITORING REPORT, REQUEST FOR APPROVAL OF THE EXPENDITURES MADE BETWEEN JANUARY 1, 2017 AND JUNE 30, 2017, AND REQUEST FOR APPROVAL OF THE REVISED PROJECT COST ESTIMATES AND CONSTRUCTION SCHEDULE PURSUANT TO O.C.G.A. § 46-3A-7(b)

I. INTRODUCTION

Georgia Power Company (“Georgia Power” or the “Company”) files its Seventeenth Semi-Annual Vogtle Construction Monitoring Report (“VCM 17 Report”) to the Georgia Public Service Commission (the “Commission” or “GPSC”) pursuant to O.C.G.A. § 46-3A-7(b).

In this filing, the Company requests that the Commission verify and approve the \$542 million of expenditures incurred for Plant Vogtle Units 3 and 4 (the “Facility” or the “Project”) pursuant to the Certificate issued in Docket No. 27800 and incurred during the Seventeenth Semi-Annual Reporting Period of January 1, 2017, to June 30, 2017 (the “Reporting Period”).

Also in this filing, the Company recommends that the Project be continued. The Boards of Directors of Georgia Power, Oglethorpe Power Corporation (“OPC”), the Municipal Electric Authority of Georgia (“MEAG”), and Dalton Utilities (“Dalton”), through the Board of Water, Light and Sinking Fund Commissioners of the City of Dalton (collectively, the “Owners”)¹ have each determined that it is in the best interests of their customers to proceed with the Project. The Owners have approved a revised cost estimate and construction schedule, which the Company submits as part of this filing. The Company requests that the Commission approve this revised cost estimate and construction schedule pursuant to O.C.G.A. § 46-3A-7(b). Pursuant to the Stipulation in this docket approved by this Commission in its Order Approving Stipulation dated January 3, 2017 (the “Stipulation”), the Company does not request any formal amendment to the certificate.

The Company also requests that the Commission approve the new project management structure in light of the realities that now exist after the Westinghouse Electric Company LLC (“Westinghouse” or “WEC”) bankruptcy. Under the new project management structure, Georgia Power, along with Southern Nuclear Operating Company (“SNC” or “Southern Nuclear”) acting

¹ OPC, MEAG and Dalton, collectively referred to as the “non-Georgia Power Owners.”

as the project manager, will manage the Project on behalf of the Owners pursuant to a revised Ownership Participation Agreement. Bechtel Corporation (“Bechtel”), one of the most respected engineering, construction and project management companies in the world, will serve as the prime construction contractor. This is the most reasonable project management structure for completing the Project. The Engineering, Procurement and Construction (“EPC”) Agreement with Westinghouse provided significant protection for all customers up until March 29, 2017, when Westinghouse filed bankruptcy. The EPC Agreement shielded customers from billions of dollars in costs that resulted from WEC’s delay in getting its design certified by the United States Nuclear Regulatory Commission (“NRC”) and WEC’s inability to effectively manage productivity at the site. WEC absorbed those costs, which ultimately led to WEC’s bankruptcy. Going forward, Georgia Power through its agent SNC will manage the remaining bulk construction phase of the Project. Under this new structure, the costs and schedule are better understood, can be effectively managed, and the risks of moving forward will be more transparent.

The most reasonable schedule is that Unit 3 will reach its Commercial Operation Date (“COD”) in November 2021 and Unit 4 will reach COD in November 2022. That schedule represents an additional 29 months for each unit from the currently approved schedule. The Owners have adopted a schedule and the associated capital cost to complete of \$9.45 billion (as of July 1, 2017). Georgia Power’s share of that estimated capital cost to complete is \$4.50 billion. Georgia Power’s share of the total capital cost of the Project is now forecasted to be \$8.77 billion. The Company asks that the Commission, pursuant to its obligations under O.C.G.A. § 46-3A-7(b), approve these proposed revisions to the project management structure, schedule and cost so that the Project may be completed. Failure to approve the new cost and schedule would provide a basis for any of the Owners to abandon the Project as provided in the revised Ownership Participation Agreement.

It also should be noted that while this forecast is the new Project capital cost and schedule that should be approved by the Commission, the actual impact on customers over what has already been approved by the Commission is expected to be approximately \$1.41 billion (excluding financing), which is net of the Toshiba Parent Guaranty, the contingency approved in the Stipulation, and the amounts that are remaining on the EPC Agreement that will now not be

paid fully to WEC but will be used to complete the Project under the new configuration and structure.

Under the Stipulation, the Company has the burden of proof to show that this new cost forecast and schedule are reasonable. The Company is confident this VCM 17 filing will carry that burden. If the Commission disagrees, it may disapprove or modify the proposed cost and schedule forecast. While the Stipulation established which party had the burden to show the reasonableness of this new cost and schedule, the Stipulation did not, and could not, alter the Commission's obligations under the law to approve, disapprove or modify the proposed revisions to project configuration, cost and schedule.

The Company recognizes that the conditions under which the Project was first certified have changed. Namely, WEC has filed bankruptcy and rejected the fixed and firm protections of the EPC Agreement. The risks that WEC bore have been shifted to Georgians. Nevertheless, continuing the Project is the better course and in the best interests of Georgia and its citizens. There is no easy choice here; this is an important policy decision that will affect all Georgians for the next 60 to 80 years. If this Commission decides in this proceeding that it is best to stop and abandon this Project, it will be for all practical purposes stopped because the non-Georgia Power Owners will not proceed without Georgia Power.

The Owners jointly agree or consent to proceed with the Project with the assumption, and on the specific condition, that all of their collective customers will be treated the same with regard to the risks they bear in going forward. The Owners each understand and acknowledge that the Commission will undertake a complete and thorough review of the revised cost and schedule forecast, and will approve, disapprove, or modify those forecasts as they pertain to Georgia Power. While the retail rates of the non-Georgia Power Owners are not regulated by the Commission, Georgia Power and the non-Georgia Power Owners have agreed as a specific condition to going forward, that any of the Owners have the right to abandon the Project and not go forward if the revised cost estimate or the revised construction schedule is not approved by the Commission, or if there is a determination by the GPSC during the VCM 17 Report review, or at any time thereafter, that any of Georgia Power's share of the total Project investment or Georgia Power's associated financing costs (except those already specified in the Stipulation)

will not be recovered in Georgia Power's retail rates because they are deemed by the Commission to be unreasonable or imprudent or for any other reason, or that such investment or associated financing costs will be presumed to be unreasonable or imprudent or unrecoverable. The reason for this condition is simple: the non-Georgia Power Owners are not willing to pass on to their customers costs that the Commission determined were unreasonable or imprudent to pass on to Georgia Power's customers. In such an event, Georgia Power and the non-Georgia Power Owners could not continue to support a Project that would lead to that result. Without all of the Owners' support, the Project could not go forward.

The decision to go forward and complete the Project followed a thorough analysis of the current situation, and was based on reasonable assumptions about the cost to complete the Project and the schedule for completion. Those forecasts are estimates based on assumptions. There were critical assumptions made about the extension of Production Tax Credits ("PTCs") and the United States Department of Energy ("DOE") Federal Loan Guarantees ("DOE Loan Guarantees"). There is uncertainty surrounding those assumptions, but those are assumptions that had to be made one way or another. They are not known facts.

There are many risks to the assumptions made when recommending that this Project go forward, including:

1. Will Toshiba Corporation ("Toshiba") be financially stable enough to meet the payment obligations of the Parent Guaranty?
2. Will WEC meet its obligations under the new services agreement?
3. Can the labor force and craft maintain the productivity improvements seen recently as the number of craft is increased as required to meet the new schedule?
4. Will the Project continue to meet the first-of-a-kind ("FOAK") challenges, including such questions as will the NRC be able to process and close the Inspections, Tests, Analyses, and Acceptance Criteria ("ITAACs") in a timely fashion to support the schedule?
5. Will the PTCs be extended and expanded as assumed?
6. Will the DOE Loan Guarantee be extended as assumed?

If any of these assumptions are not realized, the economics may not warrant going forward with the Project. As discussed later in this Report, several other risks discussed during the Certification proceedings have been somewhat mitigated by the progress made to date, but nonetheless also remain.

While the Owners recommend going forward based on the assumptions they have made, they also understand that it is important to revisit the “go/no go” recommendation as these assumptions may change over time, and the Owners and the Commission get better clarity as to whether these assumptions have or will be realized. For instance, by the time VCM 17 is decided, over \$600 million of the \$3.68 billion Toshiba Parent Guaranty should have been paid. If it is not paid, each Owner may reconsider its support of the recommendation to proceed, and the Commission would be justified in taking that fact into consideration when reaching its decision.

With this background, Georgia Power’s recommendation to go forward with completion of Vogtle Units 3 and 4 is based on the following assumptions about the regulatory treatment of this recommendation, if the recommendation to go forward is adopted by the Commission:

1. That pursuant to O.C.G.A. § 46-3A-7(b), the Commission in the VCM 17 proceeding approves the new cost and schedule forecast and finds that it is a reasonable basis for going forward; and that if the Commission disapproves all or part of the proposed cost and schedule revisions, the Company may cancel Units 3 and 4 and recover its actual investment in the partially completed Facility pursuant to O.C.G.A. § 46-3A-7(d).
2. That the Stipulation remains in full force and effect, including the Company retaining the burden of proving all capital costs above \$5.68 billion were prudent.
3. That while this Commission will make no prudence finding in the upcoming VCM 17 proceeding, nor will the certified amount be amended consistent with the Prudence Stipulation, the Commission recognizes that the certified amount is not a cap, and all costs that are approved and presumed or shown to be prudently incurred will be recoverable by Georgia Power.

4. That the Company is not a guarantor of the Toshiba Parent Guaranty, and the failure of Toshiba to pay the Toshiba Parent Guaranty, the failure of Congress to extend the PTCs, or the failure of the DOE to extend the DOE Loan Guarantees to reflect the increased capital amounts, will not reduce the amount of investment the Company is otherwise allowed to collect.
5. That as conditions change and assumptions are either proven or disproven, the Owners and the Commission may reconsider the decision to go forward.

The Company asks for specific findings on each of these points in the VCM 17 order. If the Commission disagrees with any of these assumptions at any time, including either now, during the VCM 17 proceedings, or in its final VCM 17 order, the Company recommends that the Commission cancel the Project and allow the Company to fully recover its prudently incurred investment in the partially completed Facility, along with the cost of carrying the unamortized balance of that investment. If the Commission disagrees with any of these assumptions, it may influence the willingness of one or more of the non-Georgia Power Owners to continue with the Project.

II. FILING OVERVIEW

As specified in the August 23, 2017, Commission Order Requiring Georgia Power to File Certain Information, the Company will show the following in this Report:

1. The Commission should verify and approve the expenditures of \$542 million made between January 1, 2017, and June 30, 2017. The Company's support for this position is discussed in Section VIII.
2. The results of the cost-to-complete economic analyses are based on a number of assumptions that may or may not ultimately prove to be correct; however, that analysis does show that completing Vogtle Units 3 and 4 is still an economic option. This analysis is discussed in more detail in Section VI.
3. In addition to considering the results of the economic analyses, the Commission should consider other factors in deciding whether the project should continue, such as fuel diversity benefits, the zero emissions produced by nuclear generation,

the importance nuclear generation has in our country, and the economic impact on the state and local citizens if the Project were to be abandoned. These additional factors are discussed in greater detail in Section IV.I.

4. For these reasons, the Company and non-Georgia Power Owners recommend the Project be continued.
5. In making its recommendation to continue, the Company considered many alternatives such as abandoning one or both Units and/or converting the Units to gas-fired generation, as well as qualitatively considering renewables, storage and Demand Side-Management. Completing both Units is the most economic choice and preserves the benefits of carbon free, fuel diverse base load generation for 60 to 80 years or perhaps longer. These alternatives are discussed in greater detail in Section IV.H.
6. It is in the customers' best interest of all Owners to proceed with the construction of Units 3 and 4, rather than just Unit 3 or abandoning work on both units.
7. The Owners' capital estimate to complete the Project is \$9.45 billion (as of July 1, 2017). The most reasonable schedule is that Unit 3 will reach COD in November 2021 and Unit 4 will reach COD in November 2022, which is an additional 29 months for each unit from the currently approved schedule. The Owners have adopted that schedule and the associated forecasted capital cost to complete of \$9.45 billion. Georgia Power's share of that estimated capital cost to complete is \$4.50 billion. It should be noted that while this is the new Project capital cost and schedule that should be approved by the Commission, the actual impact on Georgia Power's customers over what has already been approved by the Commission is expected to be approximately \$1.41 billion (excluding financing), which is net of the Toshiba Parent Guaranty, the approved contingency, and the amounts that are remaining on the EPC Agreement that will now not be paid fully to WEC but will be used to complete the Project.

8. The cost to cancel both Units 3 and 4 is estimated to be between \$730 million and \$760 million, of which Georgia Power's share is estimated to be approximately \$330 million to \$350 million exclusive of estimated credits from the salvage and sale of assets. It is estimated that cancellation of Unit 4 only would incur costs of \$420 million to \$490 million, of which Georgia Power's share is estimated to be approximately \$190 million to \$225 million, exclusive of asset sales. The Cancellation Estimate is discussed in more detail in Section IV.C and provided as Exhibit 5.
9. The revised cost to complete estimate, the revised proposed schedule and the cancellation analysis were performed and/or validated by several third-party experts including Pegasus-Global Holdings Inc. ("Pegasus-Global"), Black & Veatch Corporation ("Black & Veatch"), the Kenrich Group LLC ("Kenrich"), PricewaterhouseCoopers ("PwC"), and Bechtel. These analyses are discussed in greater detail in Section IV and Exhibits 5, 6, 7 and 11.
10. The Commission should approve the proposed revisions to the cost and schedule.
11. The Owners have assumed that the Toshiba Parent Guaranty will be paid, and that is a fundamental assumption for going forward. If Georgia Power was to make the opposite assumption, or if that assumption quickly proves to be no longer valid, the non-Georgia Power Owners would not be willing to go forward because the costs their customers would bear would be outweighed by the cost of abandoning the Project, and Georgia Power likewise would recommend to this Commission that the Project be abandoned.
12. The Owners responded to the Westinghouse bankruptcy quickly and effectively, including securing the full amount of the Toshiba Parent Guaranty without protracted litigation, enhancing the payment of that Parent Guaranty by establishing priority to the proceeds of WEC's sale in bankruptcy, by securing an Interim Assessment Agreement to avoid an immediate shut down of the Project, and by securing a Services Agreement with WEC to maintain the Owners' rights to the AP1000 intellectual property and maintaining the Owners' access to

WEC's engineering expertise (but not construction management expertise). These actions are discussed in greater detail in Section III.E.2.

13. This Report will explain the new project management structure with reference to the key contractors and individuals who will be responsible for completing the Project. The new project management structure is discussed in Section VII.
14. This Report will show that the decision this Commission makes regarding whether to go forward or abandon the Project, and whether to approve the proposed revisions to the cost and schedule, will affect all of the Owners and the state as a whole. None of the Owners can go forward without the others, so if the Commission determines that it is in the best interest of Georgia Power customers to abandon the Project, no other Owner will go forward without Georgia Power. Likewise, if the Commission fails to approve the revised cost estimate or construction schedule, or determines that there is some portion of costs that should not be passed on to Georgia Power's customers, the non-Georgia Power Owners will not be willing to pass on to their customers those costs equivalent to their ownership interest. In that event, the non-Georgia Power Owners will have the right to abandon the Project, and Georgia Power cannot proceed without them. This condition is discussed in greater detail in Section VII.A.

III. BACKGROUND

A. The Certification

1. *Nuclear Identified as Cost-Effective Base Load Resource: 2007 IRP and 2016-2017 Request for Proposals*

On January 31, 2007, Georgia Power filed its 2007 Integrated Resource Plan ("IRP") with the Commission in Docket No. 24505. The 2007 IRP identified a baseload need beginning in 2016. The Company's 2007 IRP further and fully evaluated the nuclear option and initiated the need for a 2016-2017 Baseload Request for Proposals ("RFP"). The 2007 IRP also showed that new nuclear units performed well under many scenarios and presented the best option to meet the baseload needs identified in the 2016 and 2017 timeframes. On July 13, 2007, the

Commission issued its Final Order approving the Company's 2007 IRP. The GPSC found that it was reasonable for Georgia Power to further investigate opportunities to build new nuclear resources.

In compliance with the 2007 IRP Order, the Company issued a baseload RFP to meet needs identified in 2016 and 2017. The RFP was conducted with the active participation of Commission Staff and the Independent Evaluator ("IE"), the Accion Group. Bids were due in response to the RFP on May 1, 2008. Pursuant to the Commission's Order, the Company was to submit its self-build nuclear proposal alongside the baseload bids received through the RFP. In addition, the Company was ordered to develop a backup plan in the event the nuclear units do not meet expectations.

As part of the RFP process, the Company conducted an extensive economic evaluation of the alternatives to Vogtle Units 3 and 4. Alternative technologies considered included the baseload generating plant options of pulverized coal and Integrated Gasification Combined Cycle, as well as continued and growing reliance on natural gas with Combined Cycle units. Alternative technologies were evaluated with varying fuel forecasts to represent the range of possible future fuel costs. In all, the economic evaluation considered 10 possible cases comprising combinations of fuel forecasts and potential carbon control cases. The evaluation methodology is consistent with the methodology that was approved by the IE for evaluation of bids to compare to the Company's self-build proposal. The IE and the Staff participated with the Company in a collaborative effort to review these economic evaluations and to create cost-effectiveness studies to understand the possible impacts of changes in assumptions. The results of the economic evaluation demonstrated the cost-effectiveness of Vogtle Units 3 and 4 across a broad range of possible future costs and risks. Completing Vogtle Units 3 and 4 was the cost-effective choice when compared to natural gas and coal alternatives.

2. Consortium and EPC Agreement

The Company evaluated various technologies for the Project including the Westinghouse AP1000, the General Electric Economic Simplified Boiling Water Reactor ("ESBWR"), the General Electric Advanced Boiling Water Reactor ("ABWR"), and the AREVA Evolutionary Power Reactor ("EPR"). An interdisciplinary group within Georgia Power and Southern

Company conducted a technical evaluation of these technologies. That group considered the then-current state of design, engineering and regulatory approvals of the various technologies. The group ultimately concluded that the AP1000 was the preferred choice. Several factors led to the selection of the AP1000 technology. Westinghouse had obtained NRC design certification of the AP1000 and was actively pursuing construction contracts to build the AP1000, both domestically and abroad. Similarly-situated utilities were also selecting the AP1000 and pursuing contracts with Westinghouse. The Company (for itself and on behalf of the other non-Georgia Power Owners) was able to negotiate favorable terms and conditions in an EPC Agreement with a Consortium consisting of Westinghouse and Stone & Webster, Inc. (the “Consortium” or “Contractor”). Negotiations for the terms and conditions contained in the EPC Agreement spanned two-years.

On March 21, 2008, the Georgia Power Board of Directors authorized management to enter into the EPC Agreement with the Consortium and Georgia Power submitted the Combined License (“COL”) Application (“COLA”) to the NRC on March 28, 2008. The EPC Agreement essentially was a “turnkey” agreement whereby the Consortium was responsible for the engineering, procurement, and construction of the Facility. The Company, as licensee with the ultimate responsibility to ensure the plant was constructed in accordance with the COL, provided oversight and was integrally involved in the day-to-day development of the Project.

The Company’s EPC Agreement with the Consortium provided significant protection to customers to protect against the type of cost overruns realized during the prior generation of nuclear plant construction during the 1970s and 1980s. The EPC Agreement was structured to share certain risks between the Consortium and the Owners where appropriate and provided incentives to the Consortium to stay on schedule and on budget. The use of indexing for certain materials and labor allowed for an appropriate sharing of risks between the Company and the Consortium while allowing the Consortium to offer an attractive price with a reduced need to include contingencies for future commodity and labor price increases. The EPC Agreement minimized the financial risk associated with potential project cost overruns by obligating the Consortium to complete the units for the stated contract price (subject to amendments, change orders and bonuses) regardless of whether the Consortium made a profit. Thus, the risk of rework, inefficiencies, and construction errors that are typical of FOAK construction was borne

by the Contractor and not to the account of the Owners. Georgia Power has consistently stated that the EPC Agreement would provide substantial protection for customers, and it did so as shown by the fact that the Consortium members wrote off billions of dollars related to the Project.

3. *Vogtle Certification and Commission Consideration of Risk Factors*

The Company filed the Application for the Certification of Units 3 and 4 at Plant Vogtle with the Commission in Docket No. 27800 along with an updated IRP filing on August 1, 2008. Specifically, the Company requested that the Commission: (1) certify Vogtle Units 3 and 4; (2) approve the 2008 IRP; (3) allow Construction Work in Progress (“CWIP”) in rate base for Vogtle Units 3 and 4; and (4) institute Quarterly Construction Monitoring and Treatment of Indexed Costs. Staff hired Dr. William Jacobs to assist them in evaluating Georgia Power’s Application for Certification of Plant Vogtle Units 3 and 4.

The Company and Dr. Jacobs both identified several Project risk categories and factors at the outset. The risk factors and risk categories included: (1) price escalation; (2) regulatory issues; (3) financial issues; (4) supply chain; (5) professional labor; (6) craft labor; (7) project execution and oversight; (8) technology risks; (9) external risks; and (10) other miscellaneous risks. Many of the risks identified related to the FOAK nature of the Project. At that point, WEC had not begun construction of an AP1000 unit in the United States, and the four units being constructed in China were not yet online.

Price Escalation:

This risk factor relates to construction cost increases due to (i) materials or labor cost escalation in excess of expectations, (ii) under-estimated quantities of equipment, materials, or supplies, or (iii) under-estimated number of man-hours required for engineering, procurement or construction. In the Certification Application, the Company explained that “in certifying the EPC agreement, the Commission will be certifying use of the indices as they actually perform, not as they are now projected to perform. The indices utilized in the EPC agreement and being applied

to owners' direct costs may fluctuate in a manner that may result in a value higher or lower than the in-service cost projected in this filing.”²

The Company explained that there was a risk that inflation rates during the construction period could be greater than the projected rate assumed in the certification request. The Company partially mitigated this risk by negotiating an EPC Agreement that included a significant portion of the cost as fixed and not subject to inflation risk.

Regulatory Risk:

The Company identified a variety of potential regulatory issues surrounding the Project. Any change in the political climate could affect the national policy regarding nuclear power, including negative impacts on incentives or NRC composition. The Project could also be impacted by new regulatory requirements, adverse decisions, or delays in plant licensing or inspection processes that materially increase cost or create uncertainty relative to licensing, construction, or operation of new plants, risks associated with delays due to site-specific issues, such as the suitability of the site or environmental issues, and risks related to regulatory compliance issues during procurement and construction.

As described in the Expert Report of Loren R. Plisco filed in the Supplemental Information Report in April 2016 in this docket, in 1989 the NRC revised its licensing regulations to establish 10 CFR Part 52 (“Part 52”) as an alternative to the existing 10 CFR Part 50 (“Part 50”) process for reactor licensing. Part 50 is a two-step licensing process where the NRC first issues a construction permit once it is satisfied with the site and safety of the preliminary plant design. Second, toward the end of construction, the utility submits an operating license application with the final design information including its plans for operating the unit(s), and the NRC issues the operating license if all the safety and environmental requirements are satisfied. The new Part 52 licensing process was designed to encourage design standardization by resolving the safety and environmental requirements before authorizing plant construction. Under Part 52, an applicant can apply for both a construction permit and operating license, called a Combined License, or COL, prior to beginning construction. This new approach was intended to provide a more predictable licensing process and reduce the risk that existed under Part 50

² Docket No. 27800, Application at 47.

when the plant submitted the operating license application near the end of construction. In part because the AP1000 design had already been certified by the NRC (Revision 15), the Company chose to proceed under the Part 52 licensing process. While Part 52 was expected to be an improvement of some of the challenges encountered under the Part 50 process, the Company also encountered many FOAK challenges as the NRC developed its interpretation of the requirements under the new regulations and how those requirements should be applied.

Dr. Jacobs addressed this new licensing process risk with the Commission during the certification, testifying that “[p]rocessing of a Combined License Application (COLA) involves many NRC regulations, standards and processes that are new and untested.”³ As a result, Georgia Power and Staff identified that delays in design approval and, in turn, delays in COLA approval and COLA issuance, may occur. During the Certification proceeding, the Company noted that the COL could be delayed because the issuance of the COL was dependent on: (1) the NRC issuing the revised design certification for the AP1000 design; (2) the NRC successfully completing the review of the standard material for the reference plant application (at the time, Bellefonte, later to be replaced with the Vogtle units); and (3) the NRC meeting its targeted milestones and the milestones established by the NRC Atomic Safety and Licensing Board for the mandatory and contested hearing required on the Vogtle COLA.⁴ The AP1000 had already been certified through Revision 15 of the Design Control Document (“DCD”) (in fact, as noted by Dr. Jacobs, it was the first and only Generation III+ reactor to have received design certification by the NRC at the time⁵); however, at the time of certification, Westinghouse was pursuing a specific set of changes to the certified design that required a safety evaluation by the NRC staff prior to implementing a rulemaking approving the design changes and issuing the Vogtle COL.

Financial Risk:

All parties knew that the size and nature of the Project could result in financial stress potentially resulting in reduced credit ratings and higher funding cost, including perceived increase in business risk. There was a risk that the Company could experience a debt rating

³ Docket No. 27800, Jacobs Pre-filed Testimony at 15.

⁴ See response to data request STF-TN-6-3, Docket No. 27800.

⁵ Docket No. 27800, Jacobs Pre-filed Testimony at 7.

downgrade during the construction of the new units under traditional Allowance for Funds Used During Construction (“AFUDC”) accounting treatment of the capital expenditures. The inclusion of CWIP in rate base during construction of the Project has supported the Company’s strong financial ratings and access to the capital markets so that the Company is financially stable and able to continue the Project despite the rejection of the EPC Agreement.

Supply Chain Risk:

This category involves the risk of being unable to obtain materials and/or equipment as needed, which could result in additional costs and/or delays. If qualified suppliers and manufacturers of AP1000 components were inadequate, there could be a negative impact on the Project schedule, and potentially on the Project cost. The majority of the major components for the units were to be fabricated overseas. For that reason, it was noted that significant disruptions in international shipping could adversely impact schedule and could potentially impact the cost of the proposed units.

As Dr. Jacobs highlighted during Certification, “...Vogtle Units 3 and 4 will be among the first new nuclear plants constructed in the United States since the 1980’s.”⁶ Dr. Jacobs also testified that:

The supply chain for nuclear grade components has diminished over the past 20 years with many manufacturers exiting the nuclear business. Re-establishment of the nuclear supply chain will be a challenge for the first new nuclear plants. The manufacturers of nuclear components will need to meet stringent quality control and quality assurance requirements. Quality problems in the supply chain could have cost and schedule impacts. Many of the largest components can only be fabricated in a few facilities in the world. Problems at these facilities in meeting schedule or quality requirements could impact project cost and schedule.⁷

Professional Labor Risk:

This category of risk that the Company identified includes potential shortages of expertise needed for the oversight, management and operations of the units. This category

⁶ Docket No. 27800, Jacobs Pre-filed Testimony at 15.

⁷ *Id.* at 16-17.

includes licensed operators and field engineering. Some of the mitigations for this risk area included allowing sufficient time to develop expertise and training programs and pre-training at existing job sites.

Craft Labor Risk:

The availability and cost of qualified labor to construct the Project represented an important factor both to the completion of the Project and the cost of the Project. Shortages of labor and/or inflation in labor rates could adversely impact the Project schedule and cost. Additional risks included potential shortages of craft labor due to increased competition from other large construction projects, training, language issues, fitness for duty regulations, strikes and walkouts. In terms of confidence about the impact of craft labor and productivity, Company witness Dr. Kris Nielsen of Pegasus-Global testified that:

Further, Vogtle's Units 3 and 4 construction labor availability and productivity is the responsibility of the consortium, relieving Georgia Power of responsibility for labor difficulties like those that it experienced in constructing Vogtle's 1 and 2.⁸

Project Execution and Oversight Risk:

The Company explained that inadequate project execution and oversight during construction could lead to additional costs, delays, or safety issues. This category also includes risks related to manufacturing and quality issues during procurement and construction and equipment problems due to new design. The Company noted that “[d]elays in finalizing the design could impact construction planning and procurement. Problems in finalizing the design in a quality manner could adversely impact the schedule for the proposed units and could potentially impact the cost of the units.”⁹ Dr. Jacobs further noted that the unavailability of vendor-provided components that could meet the design requirements could also result in cost and schedule impacts to the Project.¹⁰ In fact, a number of Engineering & Design Change Requests (“E&DCRs”) were issued by the Contractor and its subcontractors due to constructability issues and lessons learned and incorporated from other units under construction

⁸ Docket No. 27800, Tr. 536.

⁹ Docket No. 27800, Jacobs Pre-filed Testimony, Exhibit WRJ-3, Response to Data Request STF-GDS-WRJ-1-5.

¹⁰ See Docket No. 27800, Jacobs Pre-filed Testimony at 16.

such as the V.C. Summer units in South Carolina and the four units in China. This risk was identified and evaluated by the Company and the Commission when it certified the units and deemed those risks reasonable.

The standard AP1000 plant was designed to be constructed with both structural and mechanical modules. Modularization was expected to produce economies of scale, reduce costs, enhance quality control in the supply chain, and result in shorter on-site construction schedules than those experienced during the prior generation of nuclear plant construction in the U.S. As Dr. Jacobs noted, modular construction also allows many tasks traditionally performed sequentially to be performed in parallel in a controlled factory environment.¹¹ However, Dr. Jacobs also testified during Certification that “[i]f these benefits do not materialize or are less than expected, project costs and schedule will be impacted. In particular, it is anticipated that there will be a significant learning curve in the use of modular construction for a nuclear power plant. As no AP1000 units have been built, it is likely that problems will be encountered during the construction process that will require redesign and rework.”¹² The Contractor’s plan for the modules and sub-modules (structural and mechanical) was to fabricate the modules at an off-site fabrication facility and transport them to the site for assembly and outfitting. Upon receipt at the site, the sub-modules were to be assembled into completed modules and moved to their final location in the AP1000 plant. Once in place, concrete would be placed into or around the structural modules. To support this method of construction, the Contractor planned to construct a fabrication facility in the United States with a certified NQA-1 quality assurance program to meet all code requirements. As a result, the Contractor created Shaw Modular Solutions (“Shaw Modular Solutions,” currently known as “CB&I - Lake Charles”) and constructed a state-of-the-art manufacturing facility specifically to create AP1000 sub-modules. Dr. Jacobs explained that “Vogtle Units 3 and 4 will be based on a standardized design and utilize modular construction techniques. The cost and schedule benefits of the standard design and modular construction are reflected in the project’s estimated cost and projected schedule.”¹³

¹¹ Docket No. 27800, Jacobs Pre-filed Testimony at 6.

¹² Docket No. 27800, Jacobs Pre-filed Testimony at 17.

¹³ *Id.*

Technology Risk:

The Company also identified technology risks as a potential challenge for the Project. This risk relates to issues surrounding the design or technology that may create additional cost, delays, or result in suboptimal performance (regarding net electric output, thermal output and moisture carryover). The Consortium bore the vast majority of risks associated with cost overruns, delays, or suboptimal performance.

External Risks:

This category of risk relates to the potential for external events, such as Fukushima or terrorism. The Company explained that such an event could increase the cost of new nuclear plants and make state and federal approval more difficult.

Other Miscellaneous Risks:

Another risk identified by the Company related to the Company's natural gas price forecast. This risk was differentiated from "specific project risk" (e.g., the indices in the EPC Agreement do not perform as expected) and described as a "fleet risk" (e.g., commodity cost forecasts are wrong). Company witness Jeff Burleson testified that "to the extent that natural gas prices fluctuate, go up or are very volatile out in the future, that has an impact not just on five percent but on 45 percent of our generation fleet and so it is, in effect, a substantial fleet wide risk and we look at extreme volatility of natural gas prices and we don't foresee that that extreme volatility is going to end. It's -- we don't see anything that's going to cause natural gas prices to be less volatile out in the future than they are currently."¹⁴

4. Certification Order Issued

The Commission carefully considered these risks among other factors that could impact Project cost and schedule. In weighing the Project risks and benefits, the Commission ultimately granted the Company a certificate to build the Project, finding that the EPC Agreement was reasonable and that the selection of the AP1000 technology was reasonable and prudent. On

¹⁴ Docket No. 27800, Tr. 373-74.

March 17, 2009, the Commission issued an Order granting Georgia Power's certificate request ("Certification Order"). The Certification Order provided that:

- Georgia Power Company's Application for Certification of Vogtle Units 3 and 4 as modified by the Stipulation between the Commission Staff and Georgia Power Company is approved.
- The certified in-service cost of Georgia Power Company's interest in Plant Vogtle Units 3 and 4 shall be \$6,446,564,927.¹⁵
- Georgia Power Company's selection of the AP1000 technology is reasonable and prudent.
- The engineering, procurement and construction agreement entered into by Georgia Power Company is reasonable.
- Georgia Power Company shall file with the Commission semiannual and monthly monitoring reports as described in part 2 of the Stipulation.

In finding the selection of the AP1000 technology to be reasonable and prudent, the Commission based its finding on a number of findings of fact: (1) the Westinghouse AP1000 was the only new-generation nuclear design certified by the NRC at the time so it was preferable to those designs still seeking design certification at the time; (2) the AP1000 passive design technology incorporates the necessary safeguards in the event of a design-basis accident; (3) the AP1000's passive safety systems improve on the technologies of other pressurized water reactors because their simplified design requires significantly fewer pumps, valves and less cable and piping; and (4) the passive design features of the AP1000 improves the safety of the plant.¹⁶ In finding the EPC Agreement to be reasonable, the Commission concluded that "[a]lthough the risk to ratepayers is not eliminated entirely, the contract contains provisions that effectively mitigate the risk."¹⁷ The Commission further found "that by placing the risks for any additional costs related to activities requiring more man-hours or material than estimated upon the Consortium, the EPC Agreement has reasonably balanced the risks between the Company and the Consortium."¹⁸

¹⁵ Later revised to \$6.1 billion when Senate Bill 31 was signed into law.

¹⁶ *Order on Remand*, Docket No 27800 at 9-11.

¹⁷ *Id.* at 12.

¹⁸ *Id.* at 12.

B. The Project After Certification

The Certification stipulation required that Georgia Power submit semi-annual construction monitoring reports to the Commission. The filing requirements were to provide information to the Commission so that it could adequately monitor the progress of constructing the Project, ensure that the construction costs remained within budget expectations, and review and approve proposed modifications to the cost, schedule and project configuration on an ongoing basis pursuant to O.C.G.A. § 46-3A-7(b). The Commission selected Dr. Jacobs to serve as the Independent Construction Monitor (“Construction Monitor” or “CM”) in accordance with the Certification Stipulation. In that role, Dr. Jacobs has assisted Staff with all aspects of the Project. Dr. Jacobs has attended Monthly Project Review Meetings for the Project. Staff reviews the Company’s Weekly and Monthly Metrics report and submits questions raised by this report to the Company for additional information.

On April 30, 2009, Vogtle Units 3 and 4 replaced Bellefonte as the NuStart reference plant for the AP1000 COLA. Shortly thereafter, on August 26, 2009, the NRC issued an Early Site Permit (“ESP”) and a Limited Work Authorization (“LWA”) authorizing the installation of seismic category 1 backfill for nuclear islands and construction of the mud mat and mechanically stabilized earth retaining wall for Vogtle Units 3 and 4. On October 2, 2009, the Company submitted an application for an LWA-B as a supplement to the COLA to allow it to install reinforcing steel, sumps and drain lines, including rebar and other embedded items in the nuclear island foundation base slab and to place the concrete for the nuclear island foundation base slab while the Company waited for the final NRC approval of the Design Certification Amendment (“DCA”) for the Westinghouse AP1000, a condition precedent for the NRC to issue the COL for the Project. On February 16, 2010, the DOE offered Southern Company and Georgia Power a conditional commitment for federal loan guarantees. On June 13, 2011, Westinghouse issued DCD Revision 19, and the NRC staff issued the Final Safety Evaluation Report (“FSER”) for Revision 19 of the DCD in September 2011. On September 27-28, 2011, the NRC conducted the Vogtle Units 3 and 4 COL Mandatory Hearing in which witnesses for SNC and the NRC Staff testified that NRC requirements had been met for issuing the COL. On December 30, 2011, the AP1000 DCA final rule was published in the *Federal Register* and the NRC issued the COL for Vogtle Units 3 and 4 on February 10, 2012.

While the achievement of the first COL was significant, the Company has encountered numerous other challenges throughout the construction of the Project. Indeed, the Contractor faced numerous challenges related to engineering design, design changes, major equipment fabrication, and deliveries.

As was shown in the Kenrich report submitted in the Supplemental Information Report, the schedule extensions from the COD dates originally certified to the dates approved in the Stipulation were driven by a series of regulatory and implementation issues. At the beginning, these principally involved at the start a delay in WEC's obtaining approval of the DCD by the NRC, which caused a delay in the issuance of the COL by the NRC. Later they involved difficulties and delays in the fabrication of large structural modules and difficulties in obtaining final NRC approval of the basemat rebar design which delayed first nuclear concrete and containment concrete. Notwithstanding these schedule extensions and cost increases, the result of the Stipulation was a finding that all of Georgia Power's costs during this period were prudent.

Schedule changes have contributed significantly to the Project cost increases. As recognized by Dr. Jacobs, the Company exercised aggressive and proactive oversight of the Contractor and challenged the Contractor on its performance throughout the term of the EPC Agreement:

They're certainly actively involved in providing very active oversight. I think it's been very effective in ensuring the quality QC and regulatory compliance components get on the site. The company surveillance personnel have found a lot of problems with the modules that weren't found by the providers. The company's management and oversight has not been as effective in maintaining the schedule or requiring the contract to maintain the schedules that they've put out, holding them to account to meet those schedules.¹⁹

However, certain "means and methods" were under the control of the Consortium, and the Company was limited in its contractual rights and ability to access certain information and interfere with the Contractor's means and methods. Nevertheless, the Company continued to aggressively assert its oversight rights and work with the Contractor to provide more access for

¹⁹ VCM 11 Tr. 401.

the Company to exercise oversight. Commission Staff Witness Steve Roetger noted in the VCM 8 hearings that:

Georgia Power -- Southern Nuclear and Georgia Power has ramped up, as we saw as part of the increase that they requested in the eighth VCM. A big chunk of that was for oversight and compliance. So they have really ramped up their ability to provide oversight at the same time as the consortium is doing their oversight of any new vendor. And there's also been a change in the level of inclusion on the part of the consortium to allow Southern Nuclear employees to be present and there, and to observe and inspect at the same time. So it is -- it feels a lot more robust and rigorous than what we had seen in the past.²⁰

However, as noted by Dr. Jacobs in the VCM 9/10 proceeding, “Georgia Power cannot get in the business of managing the project. That’s what the consortium is hired to do and will do under the EPC Contract.”²¹ Furthermore, as acknowledged by Staff witness Dr. Jacobs, the Contractor controlled the methods and means of construction and was responsible for the Project schedule under the EPC Agreement.²²

The firm-price EPC Agreement insulated the Owners against price changes, except under specific circumstances that the EPC Agreement specified, such as changes in law. The Owners paid the Contractor for completed milestones, and the mere fact that the Contractor was required to expend more effort to accomplish the milestone was not sufficient for the Contractor to be paid more for the increased effort. As a result of this contract structure for the EPC work, the Contractor spent billions of dollars to perform this work that was not compensated by the Owners. This aspect of the EPC Agreement is apparent from the fact that Toshiba recognized a significant multi-billion dollar loss in connection with Westinghouse’s U.S. nuclear construction business and allowed Westinghouse to enter bankruptcy, largely as a result of its construction contracts with the Owners as well as the owners of the V. C. Summer project. The previous cost increases reported on the Project primarily related to time-related expenses that the Owners incurred as a result of the non-firm-priced portions of the Project, such as Southern Nuclear’s oversight and operations readiness, as well as the amounts that were paid to the Contractor in

²⁰ VCM 9/10 Tr. 334.

²¹ VCM 9/10 Tr. at 333-34.

²² VCM 11 Tr. 365-66.

settlement of the Major Claims Litigation between the Contractor and Owners, which related, among other things, to a claim of changes in law that were compensable under the EPC Agreement. While the EPC Agreement required the Owners to pay some extra amounts due to these specific circumstances, the EPC Agreement effectively shielded the Owners from increases in cost due to construction risks such as lower than expected productivity.

However, the performance of the EPC work under a firm-price arrangement also has disadvantages. The Owners had limited ability to influence the schedule or cost structure of the EPC portions of the work, which were the responsibility of the Contractor. The Contractor had the authority to decide whether to undertake schedule mitigation when critical path milestones were delayed. The Owners' remedy under the EPC Agreement for a schedule delay was limited in large part to liquidated damages. When assessing whether to undertake a mitigation action, the Contractor likely considered its costs of delays and the costs of liquidated damages in comparison to the cost of the mitigation measures and made the decision regarding whether the mitigation strategy was appropriate based on its own economic incentives under the EPC Agreement. Moreover, the Owners' insight into the Contractor's costs and schedule were limited to the deliverables that the Contractor provided to the Owners. The Owners were not always aware of cost changes, commercial discussions, and schedule changes that occurred for the EPC portion of the Project. As a result, the ability of Southern Nuclear and the Owners to manage issues that were the responsibility of the Contractor under the EPC Agreement was limited. During the Sixteenth VCM proceeding following the Westinghouse bankruptcy and during the Interim Assessment period when the Company was provided access to information it was not previously privy to, Georgia Power Witness David McKinney testified that "[b]ased on the information the company has subsequently obtained, the company does not believe that [the Contractor's] projected in-service dates are achievable and is now undertaking a comprehensive schedule and cost to complete assessment as well as cancellation cost assessment."²³

The Company also carefully scrutinized increases to the Contract Price under the EPC Agreement. Commission Staff Witness Steve Roetger also testified that "I think the Company is taking a very aggressive position on behalf of ratepayers in regard to change orders. I'm amazed at the small dollar amounts sometimes that senior management is aware of and is engaged in

²³ VCM 16 Tr. 48.

with the consortium about -- I mean, I hate to use the word small and immaterial, but you know, there are very senior executives that look at these things and they look very thoroughly at them. And I'm very pleased to report that that is a very positive work that you guys are doing.”²⁴

The original cost and schedule forecasts assumed the Project would realize potential savings from modular construction—these forecasts did not (and could not have) included extended durations based upon all the subsequent challenges. SMS experienced significant difficulty fabricating the modules and getting up to speed on required nuclear quality standards. This was in part a result of restarting the nuclear construction industry after decades of dormancy coupled with the FOAK risks of a new licensing process, plant technology, and new construction techniques.

Georgia Power had negotiated for fixed craft labor hours, fixed price equipment, indexed firm prices and other cost overrun protections in the EPC Agreement along with an index adjustment and validation mechanism. These fixed/firm provisions provided some level of cost certainty around the initial project cost estimates. In addition, the EPC Agreement limited changes to the contract price and schedule to those allowable change orders specified in Article 9 of the EPC Agreement. To the extent any of the following circumstances increased or decreased the cost to the Consortium of performing the work or impacted the Consortium's schedule for performing the work, either party was entitled to seek a change order adjusting the price or the schedule accordingly:

- physical modifications to the facilities that are required by the Owners or by the NRC (certain NRC-imposed modifications to be performed at cost by the Consortium);
- delays in the issuance of the COL beyond a specified time period, or in giving the Consortium the full notice to proceed or other required approvals (subject to the Contractor obtaining Governmental Approvals including the certification of the DCD);
- suspension of, or interference by Owners in, the prosecution of the work;
- changes in law that impact the cost or schedule for completing the work; and
- uncontrollable circumstances (such as fires, floods, earthquakes or actions by the government).

²⁴ VCM 11 Tr. 373.

As the Project progressed in the normal course, and the Company negotiated amendments with the Consortium and change orders were issued, additional costs were added to the cost forecast. Again, the EPC Agreement terms protected customers from significant risk exposure. Because of the fixed/firm nature of the EPC Agreement, the Contractors bore the cost of rework and additional costs from such errors. As a result, the Contractor issued change orders for which the Company disputed cost responsibility and ultimately these commercial disputes led to the initiation of the Major Claims Litigation between the Owners and the Consortium. Some of the disputed amounts included costs associated with design changes to the design control document and the delays in the timing of approval of the DCD and issuance of the COLs.

Because the Company selected Westinghouse's AP1000 design, it was presented with the challenges of using Westinghouse and Stone & Webster as its contractors under a dual prime contractor structure. This dual prime contractor model led to commercial issues that began to seriously impact the Project. The Company had initially preferred a prime contractor model for the Project; however, in 2008, no vendors would assume all of the risk as the sole prime contractor on the Project. As Witness McKinney stated during the VCM-14 hearings: "The Commission may recall that we - - the Company did try to get a prime contractor scenario with Westinghouse at the time. At that point in time, none of the potential vendors out there were willing to do a prime contractor scenario and take all of that risk."²⁵ As the litigation advanced and cost pressures on the Contractor increased, internal disputes regarding which Consortium member was responsible for additional costs began to impact the Project as the contractors seemingly reached an impasse that could only be resolved with the Contractor settlement and Westinghouse's decision to purchase Stone & Webster from CB&I.

C. The Stipulation

Over a period of several weeks, beginning in late August and culminating with the October 2015 Binding Term Sheet, the Company negotiated commercial resolutions and solutions for challenges across the Project. Following and in accordance with the Binding Term Sheet, the Owners and the Contractor negotiated a significant amendment to the EPC Agreement, a Definitive Settlement Agreement, and a Mutual Release, as well as change orders addressing cyber security and site security integration disputes. The totality of these resolutions

²⁵ VCM 14 Tr.123.

and process improvements is referred to as the “October 2015 Settlement.” As part of the settlement of the Major Claims litigation, Georgia Power agreed to pay the Contractor approximately \$350 million. In addition, Georgia Power also agreed to pay the Contractor approximately \$69 million for change orders relating to cyber security and site security integration issues which were not part of the Major Claims litigation. As a precondition to the effectiveness of the Definitive Settlement Agreement, Westinghouse purchased Chicago Bridge & Iron (“CB&I”) subsidiary and Consortium partner Stone & Webster and agreed to engage a new subcontractor. Mutual Releases were executed releasing all outstanding, known, and unknown claims as of the Settlement Effective Date (December 31, 2015), except for a few listed exceptions.

In December 2015, Westinghouse closed on the purchase of 100% of the shares of Stone & Webster. As a result of losses it had sustained on the V.C. Summer and Vogtle projects, CB&I announced it would take a write-off of over \$1 billion.²⁶ The settlement of the Major Claims Litigation effectively “reset” the Project. As a result of the acquisition transaction, Westinghouse gained full ownership of Stone & Webster and essentially became the “prime contractor” on the Project. One benefit of the “prime contractor” model was to eliminate the disputes among Consortium members over responsibility for cost overruns that were beginning to hinder the Project. However, the new “prime contractor” model also had the effect of placing the financial risk of cost overruns on one firm (Westinghouse) instead of spreading that risk among multiple entities. As a result, the Company negotiated for additional financial protections in the EPC Agreement, which are discussed further below.

To satisfy the precondition that it engage a new subcontractor, Westinghouse retained Fluor as its construction subcontractor for the project moving forward. Fluor transitioned to construction contractor at the beginning of 2016 and began the process of developing a basis of estimate for Westinghouse to determine what resources would be required to meet the revised schedule agreed upon in the settlement agreement with the Owners. Fluor had responsibility for Nuclear Island, Turbine Island and balance of plant construction and managed the craft labor. Fluor was released to perform their ETC by WEC in March 2016 and presented initial drafts to

²⁶ “Why Chicago Bridge & Iron ‘Sold’ its Nuclear Business to Westinghouse for a \$1B Loss.” *Forbes*, (Oct. 29, 2015).

Westinghouse on October 21, 2016. However, the basis of estimate was never presented to the Owners because that scope was within the “means and methods” of Westinghouse under the EPC Agreement. WEC later brought in Bechtel for leadership augmentation in January 2017 as WEC elected to remove scope from Fluor and self-perform the Nuclear Island construction.

On January 21, 2016, the Company filed its Application for Review and Approval of the Definitive Settlement Agreement for Plant Vogtle Units 3 and 4 and Amendment 7 to the Engineering, Procurement and Construction Agreement (the “Settlement Application”). In lieu of considering the Company’s request at that time, on February 2, 2016, the Commission issued an order directing the Company to submit its support for the Settlement Application, thus initiating a time period for Staff to review the information and to provide an opportunity for the Company, Staff and intervenors to reach a settlement. Pursuant to the Commission’s directive, the Company filed its Supplemental Information Report on April 5, 2016, and subsequently arranged meetings between Staff and the experts who submitted reports on behalf of the Company. On October 20, 2016, the Company and Commission Staff reached a Stipulation, later also joined by the Georgia Association of Manufacturers and the Georgia Industrial Group. The Commission scheduled a hearing on December 6, 2016, to consider the Stipulation and a panel of Staff and Company witnesses testified in support of the Stipulation. On December 20, 2016, the Commission voted to approve the Stipulation between the Company and the Commission Staff. On January 3, 2017, the Commission issued its written order approving the Stipulation.

D. Westinghouse Bankruptcy

Upon closing the Stone & Webster transaction in 2015, Toshiba had announced it would finalize the amount of goodwill by December 31, 2016 in accordance with U.S. Generally Accepted Accounting Principles. On December 27, 2016, Toshiba issued a news release titled “Possibility of Recognition of Goodwill and Loss related to Westinghouse’s Acquisition of CB&I Stone & Webster” discussing the possibility of additional losses related to the acquisition. The release noted that Westinghouse was evaluating the cost to complete the AP1000 units and found that the cost to complete the Vogtle and Summer projects would far surpass the original estimates, “mainly due to increases in key project parameters.” In the release, Toshiba announced the possibility of recognition of goodwill impairment and losses as high as several billion dollars. This announcement followed a 2015 accounting scandal at Toshiba where

Toshiba was found to have systematically over-stated its profits between 2008 to 2014, by approximately \$1.3 billion. As a result, Toshiba remained under scrutiny in the market and Tokyo stock exchange.

Following the late December 2016 announcement, early in 2017, Westinghouse announced that it had suffered significant losses from its AP1000 projects in the United States and planned to exit the nuclear plant construction business. On February 14, 2017, Toshiba announced that it would take a \$6.3 billion write down of its Westinghouse nuclear business. Toshiba's total market capitalization at that time was approximately \$8 billion. At the same time, Toshiba announced the resignations of Toshiba's CEO and Westinghouse's Chairman and CEO and indicated Toshiba's desire to sell all or part of Westinghouse.

In early 2017, the Contractor allowed the Vogtle Owners to view a draft Level I Project schedule along with assumption documents. This draft Level I schedule reflected the revised forecasted in-service dates of December 2019 and September 2020, with fuel load dates moving to support the new in-service dates. On February 28, 2017, the Company filed the Sixteenth Semi-Annual Vogtle Construction Monitoring Report and disclosed the new in-service dates that the Contractor had recently presented to the Owners. The Company further disclosed that it was reviewing the preliminary summary schedule supporting those dates and that the dates would need to be reconciled by the Contractor into the detailed Integrated Project Schedule ("IPS").

On March 29, 2017 (the "Petition Date"), Westinghouse and 29 affiliates commenced cases under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York ("Bankruptcy Court"). Westinghouse remains in possession and control of its assets and is operating as a Chapter 11 debtor-in-possession ("DIP"). On the Petition Date, Westinghouse also filed several motions that included two declarations in support of the motions, relating to administrative and procedural matters, payment of certain pre-petition unsecured obligations, and certain substantive matters, including Westinghouse's request for approval of up to \$800 million in DIP financing. In lieu of rejecting the Vogtle and V.C. Summer EPC agreements, on the Petition Date, Westinghouse requested approval of two separate, temporary, stop-gap Interim Assessment Agreements ("IAAs") it had executed with the V.C. Summer owners, South Carolina Electric & Gas ("SCE&G") and South Carolina Public Service

Authority (“Santee Cooper”) (together, the “V.C. Summer Owners”), and with Georgia Power, acting for itself and as agent for its non-Georgia Power Owners, respectively. The IAAs mitigated disruption to the projects resulting from Westinghouse’s failure to continue to perform its obligations while the V.C. Summer Owners and the Vogtle Owners performed assessments to determine the path forward for the projects. Pursuant to the IAAs, the Owners paid all costs incurred by Westinghouse for services performed and goods provided for the Project. The IAAs are discussed further below. On March 30, 2017, the Bankruptcy Court entered an order approving the IAAs.

In its filings at the inception of its Chapter 11 case, Westinghouse noted that, despite its recent financial troubles, the majority of its businesses are very profitable and that it planned to use Chapter 11 to reorganize around its profitable businesses and isolate them from the one specific area of its businesses that is losing money, the V.C. Summer and Vogtle projects. On April 7, 2017, the United States Trustee for the Southern District of New York appointed an official committee of unsecured creditors (the “Creditors Committee”), which is comprised of Georgia Power, SCE&G, Fluor Corporation, SSM Industries, Inc., Dastech International, Inc., Jones Lang LaSalle Americas, Inc. and the Pension Benefit Guaranty Corporation, to represent the interests of the unsecured creditors in the Chapter 11 cases. On March 31, 2017, the Bankruptcy Court entered an order approving the DIP financing on an interim basis. The DIP financing specifically precluded proceeds from the DIP financing to be used to fund Westinghouse’s obligations under the V.C. Summer and Vogtle EPC Agreements. On May 26, 2017, the Bankruptcy Court entered an order approving the DIP financing on a final basis.

While the Owners funded the mitigation efforts on the Project pursuant to the IAA, they coordinated with Westinghouse and its subcontractors and vendors to transfer primary responsibility for most of Westinghouse’s prior scope of work under the EPC Agreement, including construction and project management, to the Vogtle owners. This culminated in the parties’ entry into a new long-term agreement (as amended from time to time, the “Services Agreement”), which was approved by the Bankruptcy Court pursuant to an order entered on July 20, 2017. Pursuant to the Services Agreement, Westinghouse will support transition to the Owner-led project and will provide engineering, procurement, and technical support and staff augmentation services through completion of construction and startup. As part of their takeover,

and consistent with the rejection of the EPC Agreement described below, the Owners assumed many of Westinghouse's previous subcontracts and purchase orders and have executed, or are negotiating, new agreements with certain subcontractors and vendors who will work on the Project. On July 27, 2017, the Services Agreement became effective and the IAA expired, both pursuant to their respective terms.

On June 23, 2017, Westinghouse filed a motion seeking, among other things, to reject the Vogtle EPC Agreement. Pursuant to the order of the Bankruptcy Court that approved the Services Agreement entered on July 20, 2017, Westinghouse was authorized to reject the EPC Agreement and was deemed to reject it as of the effective date of the Services Agreement (i.e., July 27, 2017).

On July 27, 2017, Westinghouse filed a motion seeking an order extending the period during which it has the exclusive right to file a plan or plans of reorganization by three months, through and including December 4, 2017, and extending the period during which Westinghouse has the exclusive right to solicit acceptances thereof through and including February 4, 2018. A hearing on this motion is scheduled for September 7, 2017.

It currently is anticipated that Westinghouse will commence a sale process for its business assets in its Chapter 11 case in the coming months. That process is expected to conclude at the end of this year or early next year with bankruptcy court consideration of any proposed sales, followed by one or more closings of court-approved sales upon satisfaction of relevant closing conditions, potentially including, among other things, the need to obtain any necessary regulatory approvals.

E. The Company's Response to Westinghouse's Bankruptcy

1. Efforts to Mitigate the Impact of Bankruptcy on the Project

Throughout the course of the Project, Georgia Power has taken many actions designed to mitigate risks that could adversely impact successful completion of the Project. These actions include, but are not limited to: demanding that Westinghouse provide and maintain letters of credit currently totaling \$920 million, of which \$420 million will benefit Georgia Power's customers; entering into Amendment 7 to the EPC Agreement to increase the limitation on

damages under the EPC Agreement from 30% to 40% of the total Contract Price; and withholding contract retention from milestone payments per the EPC Agreement. When the Company became aware of a possible decision by Toshiba not to fund the construction business of Westinghouse in early March 2017, Georgia Power retained Rothschild and Company, an investment bank, on behalf of itself and the other non-Georgia Power Owners. In addition, the Owners retained Jones Day as bankruptcy counsel.

Specific actions that Georgia Power took in response to the Westinghouse bankruptcy include sending the Contractor a Notice of Abandonment of the EPC Agreement on March 24, 2017, and providing notice to the Contractor regarding the Owners' intent to demand payment under the letters of credit. The Company also began negotiations with Westinghouse to enter into pre-bankruptcy agreements, such as the Interim Assessment Agreement that would allow work to continue on the Project even after Westinghouse declared bankruptcy while the Owners decided the best path forward on the Project and while they negotiated with Westinghouse regarding a services agreement and with Toshiba regarding the guaranty claim. The Owners also participated on the unsecured creditors' committee to generally protect the interests of unsecured creditors, including the Owners, during the Chapter 11 cases and objected to the DIP financing because the DIP lenders sought to obtain a lien on Westinghouse's intellectual property that could impair the Owners' ability to complete the Project. This objection was successful and the final order contains specific provisions that address these concerns. During the interim assessment period, the Owners negotiated the terms of the Services Agreement and reached agreement with Toshiba regarding the guaranty claim and obtained approval of the distribution order from the Bankruptcy Court.

Actions to mitigate risks to the Project as well as other actions the Company took to mitigate the impact of the Westinghouse bankruptcy are discussed in additional detail below:

a) Contractor Financial Health Monitoring

As part of due diligence during the initial project development stages and continuing to date, the Southern Company Services ("SCS") Treasury department has routinely monitored the financial health of Toshiba and the other consortium partners. This monitoring effort includes reviewing credit opinions on Toshiba from the major credit rating agencies and monitoring major

business transactions as reported by investment banks. Since Westinghouse is not a publicly traded company, the Company has been monitoring the financing status of Westinghouse through the Toshiba financial disclosures, although that information is very limited. The results of the Company's financial monitoring of the Contractors have been routinely reported to senior management and the Vogtle Executive Oversight Committee.

b) Rating Agency Discussions

The Company also met with the major rating agencies, including Moody's, S&P, and Fitch, to discuss the current status of the Vogtle Project and impact of the Westinghouse bankruptcy. These communications were vital to ensure that the rating agencies understood the Company's efforts regarding the Vogtle Project and to support the Company's strong credit ratings to allow it to continue to access the markets at favorable terms.

c) Secondments

Although the EPC Agreement was essentially a turnkey agreement, the Company, through its oversight role, both as Owner and as agent for all Vogtle Owners, provided support for the Vogtle Project in a multitude of ways. In August 2016, the Company began seconding employees to the Contractor to assist with short-term project execution while the Contractor retained additional resources, thus continuing progress on the Project. In early 2017, as the financial situation of Toshiba/Westinghouse continued to unfold and deteriorate, the Company began seconding additional employees in fitness for duty, security and construction roles, which further benefitted the Company by providing insight into the Westinghouse organization and execution of the Project. In addition, the Company entered into Staff Augmentation Agreements with Bechtel and Westinghouse on April 28, 2017 and May 1, 2017, respectively, to allow 63 Bechtel employees to support Contractor work activities. These agreements were subsequently extended to allow SNC and Bechtel personnel to continue supporting work activities occurring on site during the transition period and, as of August 2017, more than 150 SNC personnel and more than 200 Bechtel personnel have been deployed under these agreements to assist in performing necessary work activities at the site. To further support project execution, the Company entered into an agreement with Fluor and amended the Staff Augmentation Agreement between SNC and Westinghouse in order to allow SNC to second Fluor personnel to

Westinghouse, thereby maintaining the number of Fluor personnel providing Project assistance following Westinghouse's rejection of its subcontracts with Fluor and ensuring that over 1,000 Fluor employees continued to perform Project activities following the rejection of Westinghouse's subcontracts. Overall, the secondment and support activities in 2017 served three important purposes: (1) to allow personnel who would be transitioning into new roles previously held by WEC to become familiar with these areas to ensure an efficient transition; (2) to ensure that Contractor's financial situation did not negatively impact the Project's progress before the transition could begin; and (3) to allow SNC to begin to make real-time project decisions to keep the Project moving forward during the critical analysis period.

d) DOE Loan Guarantee

In addition to the current DOE Loan Guarantees that are expected to save customers approximately \$400 million, the Company is engaged with the DOE to expand the current capacity of the original commitment. Should the capacity be expanded, the Company estimates customers will benefit by an additional \$100 to \$140 Million.

Further, the Company has entered into a third amendment to the DOE Loan Guarantee Agreement. Under the terms of the Amendment, the Company will not request any advances until the Company has made a determination to continue construction of the Vogtle Project and delivered an updated cost, schedule, and other information to the DOE. The Company will also need to enter into new construction agreements with vendors that will be primarily responsible for the Vogtle Project expansion and enter into another Loan Guarantee Agreement amendment to identify those new construction arrangements, which the Company is in the process of finalizing with Bechtel. Under the new Loan Guarantee Agreement amendment, a mandatory prepayment event requiring Georgia Power to prepay the outstanding principal amount of all guaranteed borrowings over a five-year period will be triggered if: (1) the new Services Agreement is terminated; (2) Georgia Power does not maintain access to Westinghouse's intellectual property; (3) Georgia Power decides not to continue construction of the Vogtle Project; or (4) Georgia Power fails to complete the cost assessments or enter into the replacement engineering, procurement and construction agreements by the end of 2017. The Company may also be required to make additional prepayments in connection with its receipt of payments from Toshiba under the Toshiba Parent Guaranty Settlement Agreement.

e) Production Tax Credits

The Vogtle Project will qualify for the advanced nuclear facility federal income tax credit of 1.8 cents for each kWh of electrical energy produced and sold to third parties for an eight-year period following the placed in-service date of the plant, provided the plant is placed in service prior to January 1, 2021, subject to certain limits. The Company is actively supporting bipartisan legislation introduced and passed in the United States House of Representatives and now pending in the United States Senate that would allow the Vogtle Project to continue to qualify for advanced nuclear PTCs if the units are placed in service after January 1, 2021.

f) Capitol Hill Engagement

Representatives of Southern Company and its affiliates meet with administration officials on numerous and regular occasions concerning topics important to the companies and our customers. That practice has continued in the current administration. Beginning shortly before the Westinghouse bankruptcy was announced, some of those conversations dealt with the possible impact that such a bankruptcy might have on our customers, the state of Georgia, and the nuclear construction efforts from a national perspective. Those meetings included meetings with Secretary Wilbur Ross, Secretary Rick Perry, and meetings with high ranking officials at the Commerce Department, the International Trade Administration, and DOE, as well as other high ranking White House personnel and White House advisors.

2. *Agreements Entered Into In Anticipation of Westinghouse Rejection of EPC Agreement*

a) Interim Assessment Agreement

In lieu of immediately rejecting the EPC Agreements with the Vogtle and V.C. Summer Owners, Westinghouse entered into IAAs to mitigate the risks created by Westinghouse's abandonment which allowed the Owners to fund work on the Project in a manner that was cost-neutral for Westinghouse while the parties determined if and how Westinghouse could continue to be involved in the projects, given Westinghouse's inability to perform its obligations under the EPC agreements. On March 29, 2017, Georgia Power, acting for itself and as agent for the non-Georgia Power Owners, entered into the IAA with Westinghouse for a term to expire on April 28, 2017. During the interim assessment period, the Company agreed to pay all costs related to

construction and supplies for the Vogtle Project during the term of the IAA. The IAA provided the Company with direct access to subcontractors and vendors and additional information from the Contractor to inform the Company's assessment of the best path forward for the Project and customers including, but not limited to, detailed information associated with Westinghouse's own cost to complete analysis and detailed schedule information. The Company reviewed this information as part of its ongoing assessment of the Project and determined that the December 2019 and September 2020 forecasted in-service dates for Units 3 and 4 previously provided by the Contractor are not achievable. The Company also determined that Westinghouse's continued support of the Project would be beneficial, but that support would need to transition to a more limited scope, which the Company achieved with the successful negotiation of the Services Agreement (discussed more fully below).

From April 28, 2017, through July 20, 2017, the IAA was amended eight times to allow additional time for the Company to complete its analysis of the path forward, negotiate the Services Agreement with Westinghouse and receive the required regulatory and Bankruptcy Court approvals, and negotiate a Settlement Agreement with Toshiba for the Toshiba Parent Guaranty.

The IAA provides that any payments made by the Owners under the IAA could be, in the sole discretion of the Owners, deemed an advance against any unpaid milestone payments due under the EPC Agreement and are in all events deemed to be properly part of the completion costs that are not obligations of the Owners under the EPC Agreement. While the IAA was in effect, the Company ceased making payments under the EPC Agreement and instead incurred liabilities pursuant to the IAA, of which \$414 million is included in the amount the Company is requesting verification and approval of during the Reporting Period.

The Company has actively participated in the Westinghouse bankruptcy proceedings to protect Owners' rights in that proceeding. As part of the IAA, the Owners obtained access to approximately three thousand contracts that Westinghouse held with subcontractors and vendors for substantial scopes of work that Westinghouse was responsible for under the EPC Agreement. After receiving access to these subcontracts, Southern Nuclear commenced an in-depth review of the subcontracts both to inform the ETC process and to determine how to proceed with respect to

each contract. As part of this review, Southern Nuclear examined a number of factors for each contract, including items such as the scope of work being performed, the total contract price, the amount left to be spent on the contract, the terms and conditions of the contract, outstanding invoices, and the urgency of the work to be performed. Based in part on these factors, Southern Nuclear determined how to resolve each contract.

b) Services Agreement

Following the bankruptcy filings, the Company, acting for itself and agent for the non-Georgia Power Owners, entered into negotiations with Westinghouse regarding a Services Agreement under which Westinghouse would (i) support the transition of primary responsibility for most of Westinghouse's scope under the EPC Agreement, including construction and project management, to Owners, (ii) provide design and engineering services for the balance of the Project, and (iii) provide other technical support and staff augmentation services to support Owners' completion of the Project. The parties began term sheet negotiations in April 2017, which continued in earnest through May 12, 2017, when the parties finalized and executed a term sheet containing many of the key components of the new Services Agreement. Over the next month, the parties finalized the terms of the Services Agreement, including the intellectual property licenses and scope of work. and executed the Services Agreement on June 9, 2017, subject to conditions to effectiveness including DOE, DIP lenders, and Bankruptcy Court approval.

Following execution, the parties made certain modifications requested by DOE and DIP lenders and incorporated a handful of cleanup changes. On July 20, 2017, the Services Agreement was amended and restated to incorporate these changes, but no material modifications were made. The Amended and Restated Services Agreement was approved by the Bankruptcy Court on July 20, 2017 pending DOE approval, which was received on July 27, 2017—the date the Services Agreement became effective. The Bankruptcy Court also approved Westinghouse's request to reject the EPC Agreement when the Services Agreement went into effect.

The Services Agreement provides for an orderly transition of project-level control from Westinghouse to Owners. SNC, acting as agent for the Owners, will take over the lead role for

project management, construction, procurement, testing, and startup activities. This transition process, which officially began on the Services Agreement effective date, involves assignment of many subcontracts and purchase orders from Westinghouse to Owners or, in the case of contracts that Owners did not want to assume, negotiation of new contracts with existing players or new replacement parties. The Services Agreement also includes rates for Owners' rental of certain temporary construction equipment at the site, with the option to purchase certain equipment. To reflect Owners' new role, certain compliance programs that were previously divided between SNC and Westinghouse will be transitioned to a single program for the Project (e.g., Employee Concerns Program, Corrective Action Program). Westinghouse will also transfer or make available historical data and information associated with its management of the Project and various scopes of work being transferred to Owners.

Westinghouse will serve as the primary engineering and design contractor for the remainder of the Project. Westinghouse still owns the AP1000 design and related intellectual property and will finish the remaining AP1000 design work and provide engineering and technical support through completion of construction and startup. Owners now have additional input into the design change process, including the ability to review and approve proposed changes earlier, and Owners have access to Westinghouse data needed to exercise their project management and oversight role. In the event that Westinghouse fails to perform their scope of work, Owners have a contingent right to take possession of the underlying AP1000 intellectual property necessary to enable Owners to complete the Project and operate and maintain the plant without Westinghouse's support.

In addition to engineering and design services, Westinghouse will support, to varying extents, much of Owners' work to complete the project. Some of this support will be provided via staff augmentation arrangements; the parties are currently working to define a new "meshed" organizational structure that best fits SNC's and Westinghouse's new roles. The Services Agreement scope of work includes, among other things, support for the following functions: licensing; procurement; operational preparedness; testing and operations programs; compliance; and information technology. Owners have the ability to refine Westinghouse's scope of work during the first ninety days under the Services Agreement. Following that period, Owners can de-scope services at any time and can add services with Westinghouse's consent.

The Services Agreement is a “cost-plus” contract under which Westinghouse will receive reimbursement for labor and certain expenses with an overhead multiplier and fixed fee. Westinghouse does not bear the cost and schedule risk that it bore under the EPC Agreement. Because of the protections afforded Westinghouse by the bankruptcy code and restrictions imposed by the bankruptcy process and use of DIP lender financing, Westinghouse was unwilling or unable to incur certain post-petition risks and liabilities. The cumulative balance of risk versus reward in the contract reflects this reality. The Services Agreement includes a performance standard applicable to both professional and non-professional services, which requires re-performance of defective services. The Services Agreement also includes an accelerated dispute resolution process, and in the event Westinghouse fails to perform, Owners have the remedy of taking possession of the AP1000 intellectual property.

c) Toshiba Parent Guaranty Settlement Agreement

Under the terms of the EPC Agreement, as modified by Amendment 7, if the Contractor abandoned its contractual obligation to complete the Project, the Contractor would owe the Owners and, thus, their customers, a maximum amount (subject to certain exclusions) of 40% of the contract price, or \$3.68 billion. Toshiba guaranteed the payment of Westinghouse’s liability under the EPC Agreement. As the Toshiba/Westinghouse financial situation continued to unfold in early 2017, it became clear that Westinghouse would likely abandon the Project and Westinghouse would be liable for damages in excess of amounts covered by the letters of credit that would need to be obtained from Toshiba. Although the Company held the Toshiba Parent Guaranty, the Company was concerned that Toshiba may also declare bankruptcy and be unable to meet its obligations. On March 25, 2017, Company representatives met with Toshiba counsel regarding settlement of the Toshiba Parent Guaranty. Also, to ensure that Toshiba remained committed to its obligations under the parent Guaranty, Southern Company Chief Executive Officer, Tom Fanning and Paul Bowers, Chairman, President and Chief Executive Officer, Georgia Power Company, met with Satoshi Tsunakawa, President and Chief Executive Officer, Toshiba, and Mamoru Hatazawa, Vice President and Chief Nuclear Officer, Toshiba on March 27, 2017. Other key leaders from the Southern Company that accompanied Mr. Fanning on his trip to Japan included Bryan Anderson, Senior Vice President, Governmental Affairs, SCS, and Christopher Womack, Executive Vice President and President, External Affairs, SCS. Toshiba

also expressed a desire to understand its potential liability under the Parent Guaranty and believed that certainty as to its exposure would strengthen its financial position and be viewed favorably by the financial markets.

The Company began negotiations with Toshiba to reach a settlement agreement on the finality of terms, amount and a payment schedule by which Toshiba would fulfill its obligations under the Toshiba Parent Guaranty upon Westinghouse's rejection of the EPC Agreement. The parties also agreed that Toshiba will apply proceeds from the potential sale of Westinghouse towards its payments. As discussed above, Amendment 7 to the EPC Agreement increased the Contractor's liability cap in the event of abandonment of the Project to 40% of the Contract Price. As a result, on June 9, 2017, the Company successfully negotiated a Parent Guaranty Settlement Agreement that provides that Toshiba will make payments totaling \$3.68 billion beginning with a \$300 million payment in October 2017 and ending with a final payment in January 2021.

The Toshiba Parent Guaranty Settlement Agreement is significant because it avoided costly, protracted litigation where the parties would have disputed the amount of damages to which the Owners were entitled. In addition, the Toshiba Parent Guaranty Settlement Agreement mitigates and protects Georgia Power customers from up to approximately \$1.7 billion of the additional costs to complete the Project as a result of Westinghouse's rejection of the EPC Agreement.

IV. OWNERS' ASSESSMENTS OF COST AND SCHEDULE

As it became clear that Westinghouse intended to declare bankruptcy and that Westinghouse would likely reject the EPC Agreement in bankruptcy, Georgia Power, on behalf of all Owners, undertook several studies and analyses that were essential to making an informed decision regarding the best path forward for the Project. SNC undertook an intense effort to build a Project organization that would manage the construction of the Project rather than perform oversight of construction under the firm-priced EPC Agreement. Southern Nuclear, with the access to Westinghouse's information that the Owners gained as part of the Interim Assessment Agreement, also worked to develop an estimate to complete ("Southern Nuclear ETC") that

would provide a comprehensive review of the cost and schedule of completing the Project under the model of self-performance with Southern Nuclear as the prime contractor.

Georgia Power, on behalf of all Owners, also commissioned several outside experts to provide opinions concerning the likely cost and schedule of various scenarios that were being considered:

- Kenrich provided an analysis of the cost and schedule to complete Units 3 and 4.
- Bechtel provided an independent assessment and estimate of the cost-to-complete and the schedule.
- Pegasus-Global assisted in the development of the cancellation costs for two scenarios, the cancellation of Unit 4, and the cancellation of Units 3 and 4.
- Black & Veatch provided estimates of the costs associated with demobilization of the Project and securing the site for the cancellation under either cancellation scenario.
- PwC developed a quantitative risk analysis (“QRA”) for the three options that were presented for consideration.

The Company met regularly and often with the non-Georgia Power Owners to discuss the progress of the assessments and potential options for the Project, to seek their input into the process, and to provide updates on the status of the assessments. In addition, given the changed condition by which the Owners agent (Georgia Power) would be an affiliate of the project manager (SNC), and as a condition for going forward, the non-Georgia Power Owners reasonably requested, and all Owners agreed on, several enhanced protections in the underlying Ownership Participation Agreement. These modifications include protections for the non-Georgia Power customers and enhanced reporting and governance controls.

The Owners have had full access to the analyses that Georgia Power undertook to inform their decisions of whether the Project should continue. Georgia Power and its experts have worked to respond to requests from the other Owners, and all Owners have worked together to define the estimates and reports that the Owners need to make a fully-informed decision. Using these analyses, the Owners responded to inquiries from their boards of directors, member

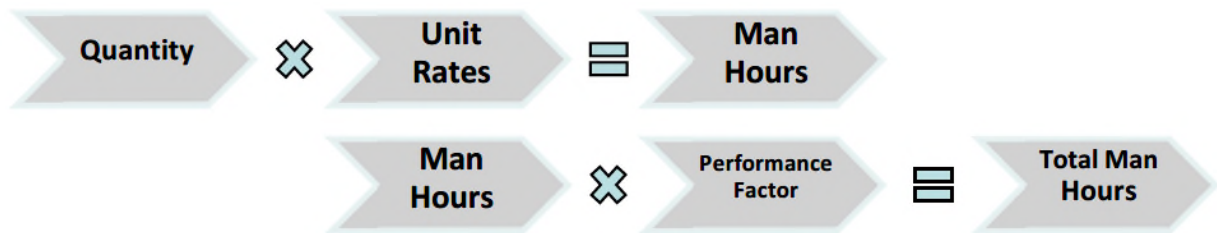
utilities, and other constituents. The Owners also considered their individual non-shareable costs, financing costs, need for power and specific circumstances to reach the optimum decision.

These studies and expert opinions are discussed below.

A. Southern Nuclear ETC

When Westinghouse and the Owners entered the Interim Assessment Agreement on March 29, 2017, the Owners, for the first time, obtained access to Westinghouse's cost information, invoices, subcontracts, and planning and schedule documents that were not previously available to the Owners under the EPC Agreement, including the basis of estimate that was developed by Fluor and was under discussion between Westinghouse and Fluor at the time of Westinghouse's bankruptcy. Realizing that the most likely outcome of Westinghouse's bankruptcy would be rejection of the EPC Agreement, Southern Nuclear commenced focused planning for development of a Southern Nuclear Project organization that could manage construction under a self-performance model. In addition, Southern Nuclear began to build the Southern Nuclear ETC, which is a ground-up assessment of the cost and schedule to complete the Project under Southern Nuclear's management, including a review and recalculation of all quantities to go. The results of that review are detailed in the Southern Nuclear ETC in Exhibit 3.

To develop the Southern Nuclear ETC, Southern Nuclear started with a detailed review of the basis of estimate that Fluor and Westinghouse developed in 2016 and early 2017. Southern Nuclear obtained Fluor's basis of estimate in conjunction with the Interim Assessment Agreement. This detailed information was not available to the Owners before this time. The direct work remaining in the Southern Nuclear ETC was calculated by determining the quantities remaining, applying unit rates to those quantities to determine labor hours, and then multiplying the labor hours by a performance factor to obtain the total labor hours of direct work remaining on the Project.



In its detailed review of Fluor’s basis of estimate, Southern Nuclear first reviewed the quantity of work remaining to be installed. In some instances, Southern Nuclear determined that the quantities remaining to be installed were not correctly reflected in the basis of estimate, and Southern Nuclear made these adjustments. For instance, Southern Nuclear reduced the amount of concrete work remaining because Southern Nuclear’s review determined that the amount remaining was less than the quantity reflected in Fluor’s basis of estimate.

After setting the quantities remaining to be installed, Southern Nuclear applied unit rates to the quantities remaining to obtain an estimate of labor hours. Southern Nuclear used the unit rates developed by Fluor, which are specific to the size, type, and location for each commodity to be installed on the Project. Southern Nuclear retained consultants Work Management, Inc. and High Bridge Associates to perform an independent assessment of the unit rates used for piping and electrical commodity installations because of the potential impact installing these quantities may have on the critical path of the installation of these commodities. The unit rates proposed by these consultants resulted in an overall difference in work hours of less 3.5%, which supported the reasonableness of the standardized unit rates presented in Fluor’s basis of estimate.

Fluor’s basis of estimate multiplied the installation rates for the size, type, and locations by a performance factor to account for differences in complexity, congestion, and other location-specific factors. The Southern Nuclear ETC uses the Fluor base performance factors, which include a 12.5% performance improvement from Unit 3 to Unit 4. This improvement is conservative when compared to historical data, which has shown a 34% improvement from Unit 3 to Unit 4. The weighted average of the performance factors used in the Southern Nuclear ETC over the nuclear island, turbine island, and balance of plant are:

	Nuclear Island		Turbine Island		BOP
Vogtle Site	Unit A 1.63	Unit B 1.49	Unit A 1.51	Unit B 1.35	1.31

The estimate of the Owners' costs under the self-performance model differs significantly from the cost risks to which the Owners were exposed under the firm-priced EPC Agreement. Under the EPC Agreement, the nature of the risks of cost increases to Owners related to schedule delay and changes in scope under the EPC Agreement. Broadly summarizing, the Owners paid the Contractor a firm price amount to perform the work, and the risk of productivity, rework, etc. was on the Contractors. If the Contractor performed more or less efficiently than expected, the Owners would nevertheless pay the same amount. As history bore out, the Contractor did in fact perform less efficiently than they assumed, their costs were substantially higher than assumed, but the amounts paid to the Contractor by the Owners were the same as specified in the contract. That situation first led the Contractor to write-off billions of dollars and eventually led to Westinghouse's bankruptcy.

Under a self-performance model, the risks that the Contractor historically bore will instead be borne by the Owners. As a result, the cost estimate depends more on certain assumptions regarding factors such as design changes and labor productivity than was true under the EPC Agreement.

The Southern Nuclear ETC accounts for the Westinghouse Services Agreement, the post-transition Southern Nuclear construction management and oversight organization, and the development of a Level 3 Schedule for Unit 3, under the assumption that Unit 4 will follow Unit 3 by twelve months. The Southern Nuclear ETC projects a cost of \$8.99 billion to \$9.91 billion to complete the Project (from June 1, 2017) and commercial operation dates ranging from +20/+20 (February 2021 and 2022 for Units 3 and 4, respectively) to +33/+33 (March 2022 and 2023 for Units 3 and 4, respectively).²⁷

Southern Nuclear developed this schedule estimate through extensive collaboration among construction, field engineering, and project controls personnel as well as expert input from Work Management, Inc. and High Bridge Associates. Southern Nuclear held daily planning sessions, in which subject matter experts examined remaining activities by building, elevation, and room, taking into account density limitations in work areas and activity logic. The scheduled

²⁷ The Owners have exercised their independent judgment that the most reasonable schedule is that Unit 3 and Unit 4 will likely reach COD +29/+29 (November 2021 and November 2022, respectively). This judgment is based on the SNC ETC and schedule, but also considering the expert opinions of others as discussed in this Report.

activities were resource-loaded by the type and number of craft that were required based on the work. This effort showed that the critical path for the Project will run through electrical installations in the Auxiliary building. Based on this analysis, Southern Nuclear and Georgia Power have established a target schedule leading to commercial operation dates of May 2021 and May 2022 for Units 3 and 4, respectively. The Southern Nuclear ETC established a bounding range described above based on possible productivity improvements and the expected schedule outcome if productivity on the Project does not exceed the currently reported metrics.

Southern Nuclear also estimated a cost-to-complete the Project, considering the Level 3 schedule described above, the structure of the Westinghouse Services Agreement, the updated Southern Nuclear construction management organization, and a review of the subcontracts that will remain in place on the Project. Southern Nuclear developed staffing curves for the construction management and project oversight organizations that were incorporated into the cost estimate. The categories included in the Southern Nuclear ETC include direct and indirect labor, field non-manual labor, procurement, subcontracts, distributables, contingency, fixed fee, escalation, Westinghouse lien cure, material and services, and Owners' non-labor costs.

For schedule, the Southern Nuclear ETC is based on a range, dependent on both schedule and productivity. The schedule range is based on a probabilistic view of the schedule, taking into consideration differing levels of productivity of the direct craft. SNC worked with the construction teams responsible for various areas of construction to review the activities necessary to support construction. Activities were then resource loaded for the type and number of craft needed, taking into consideration other factors, such as density limits.

The Southern Nuclear ETC estimate developed its direct and indirect labor estimate by establishing the remaining quantities to be installed, applying localization factors and unit rates to calculate the number of work hours required. Then, the work hours were multiplied by a performance factor based on the area of the work (Nuclear Island, Turbine Island, Balance of Plant) and the unit (Unit 3 and Unit 4). The Performance Factor multiplies the baseline work hours by a factor to account for the work hours that Southern Nuclear is projecting for the work based on the nominal conversion of remaining quantities to work hours described above. The Southern Nuclear ETC assumes that a higher performance factor will apply to the nuclear island

work and that a slightly lower performance factor will apply to the Unit 4 work. This approach recognizes that the nuclear island work may require more work for the same installed quantities and that Unit 4 will achieve increased productivity when compared to Unit 3 based in part on lessons learned. Indirect labor costs are assumed to be 33% of total craft hours.

Probabilistic schedule ranges were developed, resulting in a site “target” base working schedule of +23/+23 and a higher-confidence schedule of +29/+29.²⁸ These schedule durations equate to CODs of May 2021/May 2022 and November 2021/November 2022, respectively. SNC also undertook a “bounding” analysis to determine schedule duration in the event productivity at the site does not meet expectations. That more simplistic review yielded an outer bound of +33/+33 schedule extension, which equates to CODs of March 2022/March 2023 for the Project.

Using the probabilistic schedule ranges, SNC built a detailed cost breakdown to determine the range of costs left to complete construction. The results of the detailed cost breakdown can be found in Table 2 of the ETC. The expected cost of completion is \$9.6 billion (from June 1, 2017; the \$9.45 billion is the July 1, 2017 forward estimate based on approximately \$200 million of spend incurred in June 2017) for the +29/+29 schedule extension.

Details concerning the other categories in the cost estimate can be found in the Southern Nuclear ETC which is included as Exhibit 3 to this Report. Even following the extensive effort that Southern Nuclear has undertaken to develop a new Project organization and an ETC, Southern Nuclear continues to work on key terms that could impact the cost structure going forward.

B. Kenrich ETC

The Owners hired Kenrich to provide an analysis of the cost and schedule to complete the Project using assumptions that Kenrich developed generally independent of the Southern Nuclear ETC. Kenrich had already developed extensive familiarity with the Project because Kenrich had

²⁸ The Owners have chosen to adopt the higher confidence +29 /+29 schedule and associated revised cost-to-complete forecast of \$9.45 billion (from July 1, 2017). Georgia Power’s share of the total capital cost is now forecast to be \$8.77 billion after considering Georgia Power’s non-shareable costs, such as ad valorem taxes, and regulatory and legal fees.

served as an expert for the Major Claims Litigation and had also developed an expert report for the Supplemental Information proceeding in 2016 based in large part on its familiarity with Westinghouse's documents that were available as part of the Major Claims Litigation. Kenrich developed a separate ETC ("Kenrich ETC") that examined possible outcomes for the cost and schedule that Kenrich developed based on the new information that Westinghouse provided under the Interim Assessment Agreement and Kenrich's insight based on Kenrich's previous participation in the Major Claims Litigation. As explained in more detail below, the Kenrich ETC's schedule forecast is based on installation rates that have been sustained historically on nuclear projects as well as on the progress achieved historically on the Project, and the Kenrich ETC's cost forecast relies on productivity rates, a potentially extended schedule, costs observed on the Project, and other considerations.

Regarding the schedule, the Kenrich ETC examined the schedule using three different approaches. The first methodology looked to sustained installation rates of bulk electrical and mechanical commodities. The second and third methodologies extrapolated from the earned value metrics used for nuclear island construction and overall Project completion. Kenrich developed early and late projections using each of these methodologies, informed by Kenrich's expertise in this area, historical nuclear construction installation rates, and progress on the Chinese AP1000 units at Haiyang and Sanmen. Based on this information, the Kenrich ETC projects commercial operation dates ranging from February 2021 to November 2022 for Unit 3, with Unit 4 following Unit 3 by twelve months.

The Kenrich ETC included cost projections for the Project by assuming improved productivity, similar-to-historical productivity, and worsened productivity. To build up its cost estimates, Kenrich developed models and assumptions for direct labor, direct subcontracts, indirect construction costs such as field non-manual labor, non-construction costs such as procurement, and other costs such as markups and fees. Direct labor costs are a critical component to the Kenrich ETC. Kenrich calculated the costs of direct labor by utilizing an estimate of the budgeted work hours remaining, multiplied by three performance factors, considering improved performance, performance that is comparable to the performance observed on the Project between June 2016 and February 2017, and worsened performance. Kenrich utilized appropriate models for the other cost categories, also accounting for variations that

would occur as a function of the Project schedule or changes in direct labor productivity. For instance, worsened direct labor productivity will result in higher construction indirect costs and non-construction costs that support the direct labor. Based on this information, the Kenrich ETC projects a cost to complete range, as of June 1, 2017, of \$7.4 billion (representing improved productivity and the earlier commercial operation date) to \$10.1 billion (representing worsening productivity and the later commercial operation date). Georgia Power's share of this amount would be \$3.4 billion to \$4.6 billion. These amounts do not include Owners' costs which were included in the economic analysis.

The Owners consider the Kenrich ETC to be a reasonable sensitivity on the Southern Nuclear ETC. The Kenrich ETC is an independent analysis using different methodologies. While the Kenrich ETC presents a longer delay range and larger cost increase, the Kenrich projections are in general agreement with the Southern Nuclear ETC. The Kenrich commercial operation date range equates to a +20/+20- to +41/+41-month extension beyond the most recent approved schedule dates pursuant to the EPC Agreement, which is in reasonable agreement with the dates presented in the Southern Nuclear ETC.

C. Cancellation Estimate

The Owners recognized that an analysis of the costs of cancellation would be necessary to fully inform the go/no go decision for all Owners. The Owners retained Pegasus-Global to develop the cost categories for cancellation ("Cancellation Estimate"). Pegasus-Global visited the Vogtle construction site in March 2017 to familiarize itself with the Project site and to obtain a better understanding from the Project personnel as to the status of construction to date and what additional information would be needed to assess cancellation, including site demobilization. The Cancellation Estimate includes an estimate of the Owners' potential liability to subcontractors and vendors, an estimate of the costs to physically demobilize the site and place the site in an acceptable condition, an estimate of employee severance cost, and an estimate of Southern Nuclear and Georgia Power overhead to manage these efforts. The Company hired Black & Veatch to develop the estimate for site demobilization. The Cancellation Estimate is a high level, order-of-magnitude estimate of the costs that would be incurred to cancel the Project.

To develop the site demobilization estimate, Black & Veatch conducted site visits in April 2017, conducted appropriate walk downs and examination of the physical structures on the site, and followed up as necessary with Georgia Power and Southern Nuclear employees. Site demobilization costs involve placing the site in a safe condition, scaffolding dismantlement, establishing a permanent security perimeter, and other costs of this nature. If the Project is cancelled, it will be necessary to develop the work scope further to place the site in an acceptable condition. If the ultimate condition of the site differs substantially from the assumptions in the Cancellation Estimate, then the overall cost of cancellation will also differ.

Ultimately, the Cancellation Estimate estimated that cancellation of both Units 3 and 4 would incur costs between \$730 million and \$760 million, of which Georgia Power's share totals approximately \$330 million to \$350 million exclusive of estimated credits from the salvage and sale of assets. The Cancellation Estimate projects that asset sales and salvage from both Units 3 and 4 could net approximately \$35 million to \$115 million, of which Georgia Power's share would be \$15 million to \$50 million. Salvage prices for the assets in the event of cancellation would be highly dependent on the worldwide market for the high-value AP1000 components such as the steam generators, so the amounts that the Owners would ultimately obtain would be highly dependent on factors outside of the Company's control, and would most likely be biased towards the lower end of the range.

Cancellation of Unit 4 only would incur costs of \$420 million to \$490 million, of which Georgia Power's share totals approximately \$190 million to \$225 million, exclusive of asset sales. The Cancellation Estimate projects that asset sales and salvage could net approximately \$15 million to \$50 million, of which Georgia Power's share would be \$5 million to \$20 million.

This Cancellation Estimate contemplates securing and stabilizing the site and not the dismantlement and removal of the installed structures. Restoration to greenfield conditions is a significantly costlier undertaking than abandonment and is not included in this analysis. These costs are not included in the estimate because it is assumed for the purposes of this analysis that the site will ultimately be restored to the same condition in either case. While the timing of these expenses may differ, these costs will be incurred in either scenario and are not included for the

purposes of this decision. Efforts such as collapsing the cooling towers would likely not take place until after Vogtle Units 1 and 2 cease operation even if the Project is cancelled.

In addition to the costs that are common to all Owners, Georgia Power will have additional, non-shareable costs. The potential loss of interest savings associated with the DOE Loan Guarantee is the largest portion of these costs. The financing implications of cancellation will differ for the other non-Georgia Power Owners.

This Cancellation Estimate provides an important input to the recommendation that the Company has made concerning the future of the Project; however, as stated above it is important to understand that the Cancellation Estimate is a high-level estimate for consideration in making this decision. It is not a detailed engineering analysis of the structures and guarantee of these costs. Therefore, in the event that the Project is cancelled, the Commission should be aware that there is a significant chance that the expenditures required to demobilize and stabilize the site would vary from the amounts in this estimate. Also, since the work underlying the Cancellation Estimate was completed, construction has progressed to a different state, and the status of liens and subcontracts has changed. Therefore, the costs of cancellation presented in the Cancellation Estimate should be interpreted as an approximation for inclusion in the economic analysis, not as a detailed cost estimate of the costs of cancellation.

D. Deferral Costs

The Owners also requested that Black & Veatch build an estimate for the long-term deferral of both units and Unit 4 only to obtain an estimation of the likely costs of deferral going forward. Deferral costs are highly uncertain because, among other reasons, the period of deferral would be uncertain. Black & Veatch's estimate provides an approximate monthly cost of deferral that contemplates a deferral period of up to ten years; however, the actual monthly cost during the deferral period and the actions that the Company took to preserve items and keep the Project ready for remobilization would vary based on the anticipated deferral period. Black & Veatch's high-level estimate of deferral costs indicated that the costs for all Owners without contingency of deferring both units would be approximately \$112 million, with approximately \$1.9 million in monthly deferral costs during the period for which the Project is deferred. Furthermore, deferral

of Unit 4 only (assuming completion of Unit 3) would cost approximately \$51 million for all Owners, with \$1.2 million in monthly deferral costs.

This cost estimate includes only the costs of physical demobilization and preservation and does not take into account any commercial liability, overhead costs, or other possible costs that may be associated with deferral. For example, the impact of deferral to the Company's DOE Loan Guarantees is not taken into consideration. Developing an estimate for deferral costs is difficult and uncertain because the deferral duration is not presently known. Additionally, the cost of remobilizing the site is highly uncertain and will depend on factors such as prevailing labor costs that exist at the time remobilization is attempted. If the Project is deferred, there will be no AP1000s under construction in the United States. As a result, it is likely that Westinghouse would not undertake the efforts that would be required to maintain the design or complete the remaining engineering and licensing work. Existing procurement vendors may also eliminate and scale back their production of nuclear-qualified components.

As a result of these and other factors, the Owners did not perform a formal economic analysis of the deferral.

E. Quantitative Risk Analysis

PwC was contracted to perform a QRA of the Southern Nuclear ETC. The purpose of the QRA is to build up the risks of which the Company is aware into an estimate of the impact of these items on the final cost. While the existence of several low probability risks may not have a meaningful impact on the baseline cost estimate, it is likely that some of these risks may come to fruition, even if this outcome cannot be predicted today. Given rough orders of magnitude estimates of impact and probability, the QRA uses a Monte Carlo analysis to run multiple iterations of the risks. The QRA then develops a confidence interval by looking to the fraction of the iterations that fall below a threshold cost and report this number. For example, the "P90" estimate shows the value for which 90% of the iterations produce a cost that is less than the value. It is crucial to understand that these calculations account for only those risks that were identified and input into the model: the QRA does not contain any information regarding other risks that are not contained in the model, some of which may have significant impact on the final cost of the Project. The QRA collapses known, modeled risks into a range of outcomes for

consideration. It is inevitable that other risks that are not accounted for in this model will exist or that some of the risks that are included will manifest themselves in a manner different from the way in which they were quantified, and some of the risks considered may not come to fruition.

To develop and quantify the risks that were included in the QRA, PwC met with personnel from Georgia Power, Southern Nuclear, and the other outside experts to gather the needed information from the subject matter experts. Using the input from the subject matter experts, PwC developed its QRA model and ran iterations to converge on a risk-adjusted cost for the three scenarios under consideration. PwC then evaluated its results by reviewing and validating the inputs, testing the results, and comparing the results to the assumptions underlying the model. PwC then generated its report that summarizes its findings and presents the risk exposures and confidence intervals.

PwC's QRA includes estimate uncertainty risk, which captures the risk that the estimates provided by the experts are not correct, and event-driven risks, which account for factors that could negatively impact the projected amounts but are not included in the estimate. These factors included items such as increases to the prevailing craft labor rates that were not included in the Southern Nuclear ETC but were recognized as potential risks to the final cost of the Project. The PwC QRA concluded as follows:

Summary of Risk Adjusted Cost Estimates for the Plant Vogtle Units 3 & 4 Scenarios

No.	Scenario	Risk Adjusted Est. (\$M) P20	Risk Adjusted Est. (\$M) P80	Key Cost Drivers
1	Complete Units 3 and 4 Based on the SNC ETC	\$8,981	\$10,129	<ul style="list-style-type: none"> Construction productivity Schedule duration
2	Cancel Units 3 and 4	\$671	\$782	<ul style="list-style-type: none"> Terminating subcontractors Yard demobilization Equipment Resale/Salvage
3	Complete Unit 3/ Cancel Unit 4	\$6,219	\$7,023	<ul style="list-style-type: none"> Completion of Unit 3 Demobilization of Unit 4

As discussed above, the QRA has taken recognized and quantified risks that are included in the model and calculated the above results. These results show a composite of the recognized and

quantified risks that were included in the model and should not be interpreted to mean that the final Project costs are guaranteed to be in the ranges discussed above.

F. Bechtel Schedule Review

In conjunction with its review of the progress on the Project, Bechtel conducted a review of the Project's cost and schedule estimates. The cost estimate examined direct construction labor, field non-manual labor, indirect construction labor, equipment and materials, and associated other direct costs, and the schedule estimate examined all to-go direct and indirect construction activities through mechanical completion. Bechtel's review included an analysis of the logic of civil and structural activities, peak craft density and congestion. In its review, Bechtel applied rates that were informed by Bechtel's historical experience in nuclear plant construction. Historical data from previous Bechtel nuclear power projects was used as a basis for the schedule assessment

As part of the assessment, key Bechtel personnel conducted walkdowns and undertook an independent review of congestion, schedule logic, the productivity of the craft, and other related items. Bechtel's assessment also described key risks with that would affect its assessments. These risks include engineering quantity and constructability risks, craft labor risks, risk from multiple interfaces, and risks from rapid transition in project execution.

The assessment focused on the construction work scope that falls under Bechtel's purview and assumes that other work areas, such as the issuance of work packages and delivery of procurement items, will support construction need. Bechtel's estimates address the construction work in Bechtel's scope of work from September 1, 2017, to mechanical completion and does not assess Southern Nuclear's estimates for work that would be outside Bechtel's scope or occur after mechanical completion. Based on these and other assumptions, Bechtel's probability analysis of the schedule showed a schedule of +19/+19 months delay (P50) and +24/+21 months delay (P80), which falls well within the bounding range of the Southern Nuclear ETC. The figure below illustrates some of the factors that Bechtel considered in developing these schedule estimates, including its considerations for evaluating the separation between Units 3 and 4.

Unit 3		Base Date	Jun-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	P80	Definitions
Evaluation Criteria		Jun-19	+12	+15	+16	+17	+18	+19	+20	+21	+22	+23	+24	Jun-21	
Overall Percent Complete															
Craft Manpower by Facility															
Total Craft Manpower Site Accommodations															
Site Total Sustained Rates															
Sustained Rates by Facility															
Percent Complete by Commodity to FL															
Unit 4			May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22		Definitions
Evaluation Criteria		Jun-20	+11	+12	+13	+14	+15	+16	+17	+18	+19	+20	+21		
Overall Percent Complete															
Craft Manpower by Facility															
Total Craft Manpower Site Accommodations															
Site Total Sustained Rates															
Sustained Rates by Facility															
Percent Complete by Commodity to FL															

Bechtel's cost assessment for the work that Bechtel will assume in its direct hire construction scope yielded a cost of \$4.12 billion, inclusive of direct craft labor, field indirects, field non-manual services, and Bechtel home office services. By comparison, the Southern Nuclear ETC estimated that this scope of work would cost \$4.26 billion. Bechtel developed its assessment from Southern Nuclear's determination of the quantities remaining to be installed, applying unit rates to these quantities based on Bechtel's historical experience in nuclear power plant construction. The unit rates were further adjusted for other factors such as the conditions on the Project site, congestion, and senior Bechtel construction personnel input. Bechtel independently developed an estimate of required indirect labor and created a staffing plan for field non-manuals. Bechtel's estimate applies an overall contingency of 12.2% to account for uncertainties that Bechtel can control such as productivity, pricing, and quantities; however, this contingency does not include items such as scope changes.

G. Contractor/Subcontractor Negotiations

The Company also began soliciting bids from potential construction contractors, including Fluor and Bechtel, and ultimately selected Bechtel as the construction contractor. As discussed above, Bechtel performed an independent ETC to support its bid for the construction contract for the Vogtle Project. The Company also undertook the arduous task of reviewing Westinghouse's subcontracts to determine which subcontracts should be retained and which should be renegotiated or terminated when it took over construction of the Project.

H. Other Options Were Considered

In coming to their recommendation, the Owners considered many options concerning how to proceed with the Project. The primary options considered by the Owners included:

- Completing Units 3 and 4
- Completing Unit 3 and cancelling Unit 4
- Cancelling Units 3 and 4.

The Owners considered other options but ultimately determined that the three options listed above were the most competitive options for detailed analysis and final consideration. For instance, the Owners considered deferral of Units 3 and 4, completion of Unit 3 and deferral of Unit 4, renewables, storage, Demand-Side Management (“DSM”) and conversion of the existing Vogtle structures to natural gas combined cycle facilities, as further discussed in Section VI.B. Preliminary investigation of the feasibility and cost of these options revealed that these other options did not warrant the in-depth analysis that the Owners undertook for the other three options that were presented for final consideration. Simply put, these other options would be significantly less economical for customers than the options that Georgia Power and the Owners included in their in-depth analysis.

Deferral would involve demobilization and stabilization of the site, maintenance of the site during the deferral period, and remobilization and completion of the Project at a subsequent time. The costs of these activities would be significant, and the Project would face added uncertainty with respect to the costs of remobilization, the availability of procurement items, and the NRC’s treatment of deferral under 10 CFR Part 52. Furthermore, the length of the deferral period would be uncertain. While deferral is a legitimate option that other utilities have selected for nuclear power plants in the past, the challenges and additional costs associated with deferral led Georgia Power to conclude that deferral would not be in the best interest of customers when compared to other available options.

I. Other Factors Support Continuing the Project

Based on the Owners' assessments, the Owners have determined that continuing the Project and completing both Units 3 and 4 continues to be in the best interest of their customers. Continuing the Project will provide customers with a source of carbon-free, reliable base load generation for sixty or more years. Nuclear generation remains an important hedge against the impact of potential carbon costs and fossil fuel cost volatility that could impact the Owner's ability to provide economic power to customers over the next several decades. In addition, the Vogtle Project will continue to provide jobs and strengthen the economy not only in Burke County and the surrounding areas but the entire state of Georgia. Continuing the Project is not only beneficial to the state of Georgia but, as the only nuclear units currently under construction in the country, the Project is important to the country and its nuclear generation industry as a whole. Continuing the Project will maintain and continue to develop a workforce and supply chain necessary to service a civilian nuclear industry. It is vitally important that the United States continues to maintain a foothold on nuclear technology as other countries such as China and India continue to develop their nuclear generation construction programs. It is true that the benefits to the nation at large should not be funded entirely by Georgians. In that regard, the fact that WEC and Toshiba have already contributed billions of dollars to the effort at Plant Vogtle adds to the belief that we should not waste that investment by abandoning the Project.

As discussed above, nuclear generation is a vital part of a clean air/zero carbon emissions future. As coal-fired plants are shut down across the Company and potential carbon regulations are considered, nuclear and renewables will have an ever-increasing importance in providing customers with cost-effective, clean, reliable energy. Natural gas generation is currently very cost-effective and serves a vital role in the country's energy mix today, but as noted by many experts, there could come a time when the country needs baseload generation from non-carbon emitting sources.

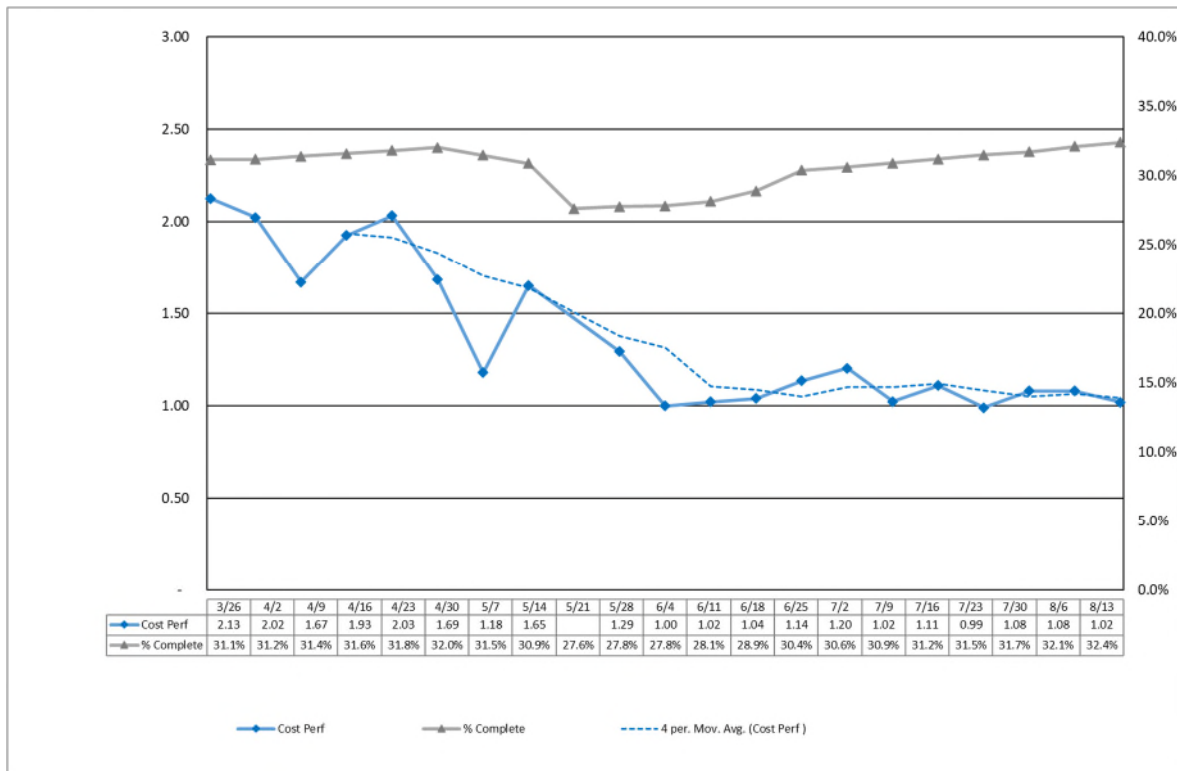
The Vogtle Project remains vitally important to the local economy and comprises the largest source of skilled building trade in the country today, employing thousands of skilled craft labor, and will create approximately 800 permanent jobs upon construction completion. Not only does the Vogtle Project provide thousands of jobs, it is also serves as an important source of revenue to Burke County and the surrounding areas providing significant tax revenues to fund

excellent schools and infrastructure. In addition, many local businesses have emerged to support the influx of workers into the area, further stimulating the local economy.

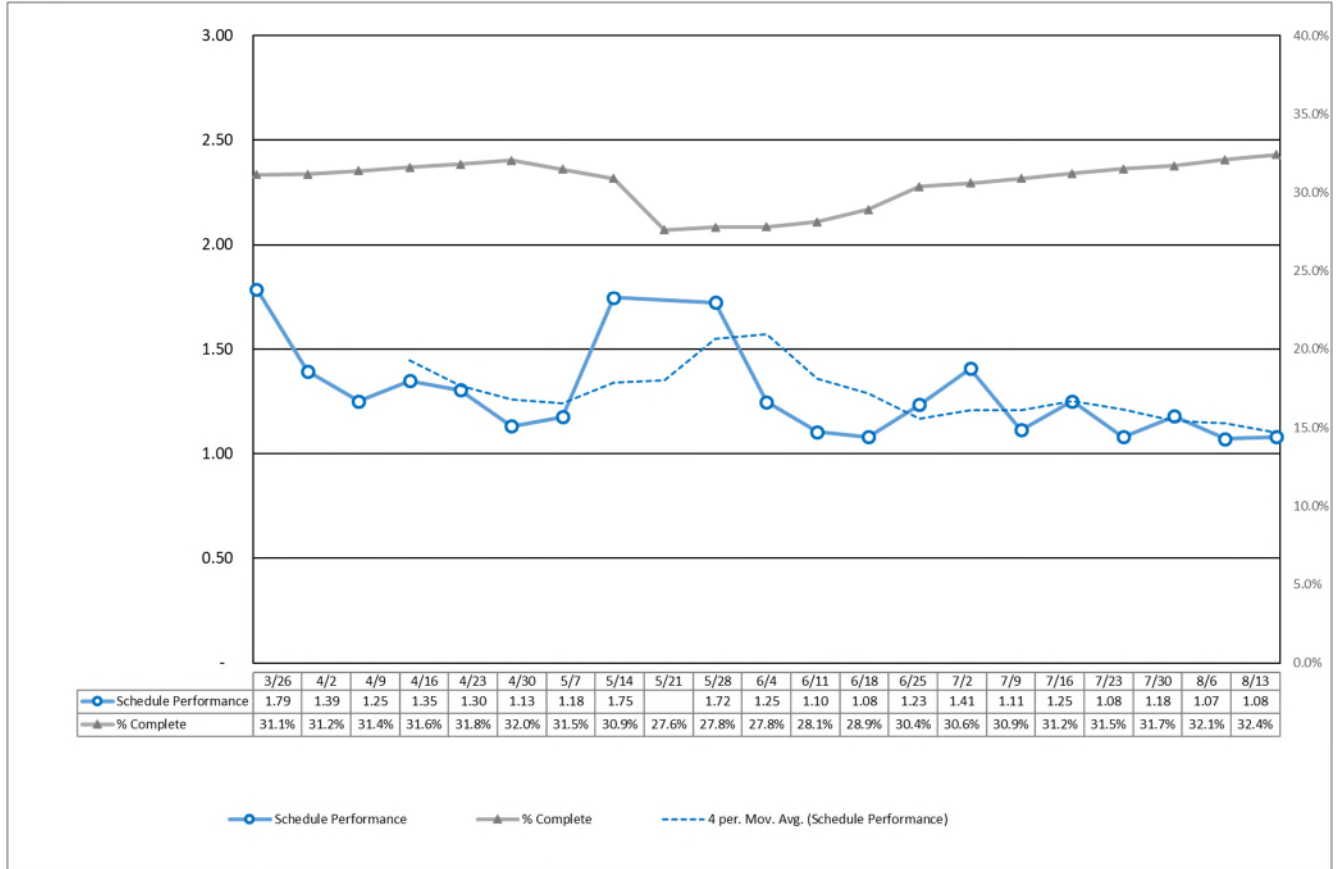
Also, it is vitally important to the nation's nuclear generation fleet to maintain a workforce and supply chain to support new nuclear facilities. As noted by many experts, part of the challenges Vogtle and V.C. Summer have encountered are due to the restart of the nuclear plant construction industry after a three-decade hiatus. Continuing the Vogtle Project will ensure that there is a skilled labor force and a supply chain that understands the NRC nuclear-grade and quality requirements for nuclear plant construction.

The IAA minimized the impact of Westinghouse's bankruptcy on the Project. Approximately 6,400 workers were present for work on March 29, 2017, after Westinghouse filed for bankruptcy. On other projects, long time periods have elapsed with no work taking place while the utility owners and the contractors worked out an agreement regarding bankruptcy or waited for resolution of the issues by a bankruptcy court. The IAA avoided delays while allowing the Owners to assess available options for the Project. The information that the Owners obtained through the IAA was vital to developing estimates of the cost to complete or to cancel the Project that inform this critical decision. Moreover, the IAA enabled the Owners to retain qualified labor on site, advance construction progress, and give the Company the necessary time and information to make a fully-informed decision about the best manner to proceed. The IAA also avoided demobilization of the work force, which could make full remobilization of a qualified work force to complete the Project difficult or impossible. Moreover, since Southern Nuclear has taken a more direct construction management role on the Project, the Project has been moving toward meeting the cost and schedule goals set by Southern Nuclear, and schedule performance and cost performance productivity continues to trend towards 1.0 (which is Southern Nuclear's goal), as demonstrated in the figures below. July 2017 construction progress exceeded the plan.

Vogle Site Cost Performance



Vogtle Site Schedule Performance



V. ADDITIONAL ASSESSMENTS BY GEORGIA POWER

A. Deferred Benefits Are Largely Offset by Deferred Operating Costs

To date, the revised extended schedule has added minimal incremental schedule-related costs to customers. These schedule-related costs include financing charges, O&M, depreciation, and ad valorem expenses. Focusing only on the delayed fuel savings is one-sided in determining the impacts related to schedule delay. Financing costs would continue to be incurred whether the units come online under the prior schedule or the revised schedule. Moreover, delayed fuel savings are offset by the avoided O&M and depreciation expense that are not incurred during construction as shown in the figure below. In order for customers to benefit from fuel savings expected to be realized by the Project, customers would have to bear the O&M and depreciation costs associated with placing the Project in service.

Replacement Energy Costs and Deferred Operating Costs

Million of Dollars

Date	VCM	Deferred Benefits		Deferred Operating Costs			Total Deferred Operating Costs	Net Cost
		Replacement Energy Cost	Deferred PTCs	O&M	Depr.	Ad Valorem		
Apr-16	15th	3.0	10.0	(7.2)	(4.6)	(1.1)	(12.9)	0.0
May-16	15th	3.1	10.0	(7.1)	(4.6)	(0.8)	(12.5)	0.5
Jun-16	15th	4.8	10.0	(7.3)	(4.6)	(1.1)	(12.9)	1.8
Total		10.9	29.9	(21.6)	(13.8)	(3.0)	(38.3)	2.4
Jul-16	16th	6.2	10.0	(7.6)	(4.6)	(1.1)	(13.2)	2.9
Aug-16	16th	6.1	10.0	(7.7)	(4.6)	(1.1)	(13.3)	2.7
Sep-16	16th	5.8	10.0	(7.5)	(4.6)	(1.1)	(13.1)	2.7
Oct-16	16th	5.3	10.0	(7.7)	(4.6)	(1.1)	(13.3)	1.9
Nov-16	16th	4.0	10.0	(7.6)	(4.6)	(1.1)	(13.2)	0.7
Dec-16	16th	5.4	10.0	(7.4)	(4.6)	(1.0)	(13.0)	2.4
Total		32.8	59.7	(45.4)	(27.5)	(6.3)	(79.2)	13.4
Jan-17	17th	5.2	8.2	(7.4)	(6.2)	(1.3)	(14.9)	(1.5)
Feb-17	17th	3.5	8.2	(7.4)	(6.2)	(1.3)	(14.9)	(3.2)
Mar-17	17th	6.1	8.2	(7.2)	(6.2)	(1.3)	(14.7)	(0.4)
Apr-17	17th	11.8	17.5	(15.2)	(10.4)	(2.4)	(28.0)	1.4
May-17	17th	11.1	17.5	(15.1)	(10.4)	(2.4)	(27.8)	0.8
Jun-17	17th	10.4	17.5	(15.2)	(10.4)	(2.4)	(28.0)	(0.1)
Total		48.2	77.0	(67.4)	(49.7)	(11.2)	(128.3)	(3.2)
Total to Date		91.8	166.6	(134.4)	(90.9)	(20.5)	(245.8)	12.6

Assumptions:

1. Replacement Energy Cost compares the actual hourly Pool Interchange Rate ("PIR") to the estimated Vogtle 3&4 average cost.
2. O&M is calculated by taking the current forecast Post COD O&M adjusted for inflation and netting with current period actual Pre COD O&M.
3. Depreciation is the current forecast post COD.
4. Ad Valorem is the current period actuals.

In addition, the Company continues to be bound by the terms of the Stipulation and the agreed-upon customer protections that limit the collections under the Nuclear Construction Cost Recovery ("NCCR") tariff to the financing costs incurred only on the capital costs up to the certified amount of \$4.418 billion in addition to the agreed-upon ROE reductions.

It is important to remember that constructing Plant Vogtle Units 1 & 2 faced many difficult challenges including schedule extensions and cost increases. However, the decision to

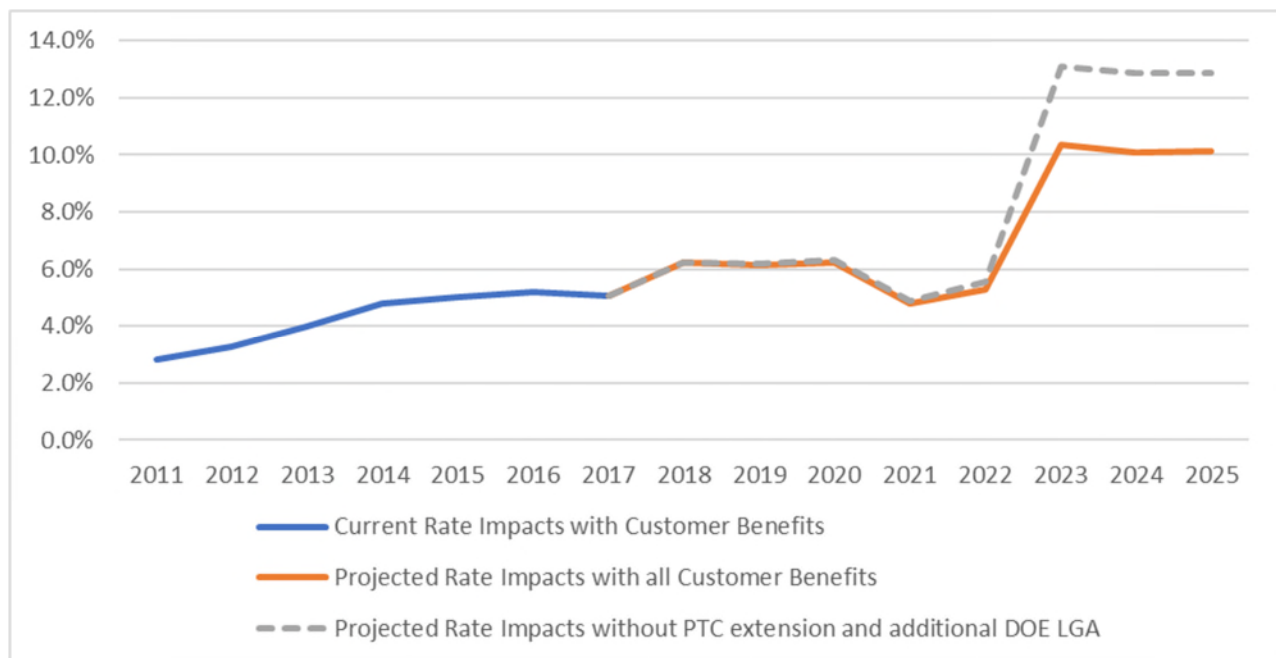
proceed with Units 1 and 2 has proven to be a prudent choice, and today Plant Vogtle Units 1 and 2 are the “crown jewels” of the Company’s generation fleet.

B. Customer Rate Impacts

For the +29/+29 case, the projected peak rate impact to retail customers is 10.3%, with approximately 5% already in rates. Consistent with previous VCM reports, the rate impacts include customer benefits that the Company proactively pursued – including PTCs and interest savings from DOE Loan Guarantees. The projections also include lower financing costs and the fuel savings associated with adding additional nuclear units to the generation mix.

The figure that follows shows the expected rate impacts with and without an extension to the PTCs and an expansion of the DOE Loan Guarantees.

Figure A – Projected Cumulative Rate Impacts



C. Board of Director Involvement:

Georgia Power kept both the Southern Company Board of Directors and Georgia Power Board of Directors fully informed of the Project status during the interim assessment period. Ultimately, the results of the Company’s assessments were presented to both the Safety and Nuclear

Committee of the Georgia Power Company Board on August 15, 2017, and the full Georgia Power Company Board on August 16, 2017. The Georgia Power Board was very engaged, asked a number of probing questions, and discussed and balanced the risks of going forward or stopping the Project. Their final decision was to recommend to the Commission that the Project continue under certain conditions, those being:

- The Georgia Public Service Commission approves in VCM 17 that:
 - The cost and schedule are reasonable;
 - The current prudence stipulation remains in effect;
 - The certified amount is not a cap;
 - The company is not a guarantor of the Toshiba Parent Guaranty;
- Toshiba complies with its obligations to pay the \$3.68 billion as detailed in the Toshiba Settlement Agreement.
- The Vogtle Owners all agree to proceed with construction.

VI. ECONOMIC ANALYSIS

As discussed below, although there are some changes to the assumptions made and factors included in the analysis, the economic analysis performed for VCM 17 Report has relied on the same core methodologies used in all previous economic evaluations conducted in Docket Nos. 27800 and 29849. That is, the economic evaluations presented in this VCM 17 Report compare the cost of completing Plant Vogtle Units 3 and 4 versus stopping the Project, and alternatively, constructing new natural gas-fired units at the next capacity need. In addition to analyzing a range of possible cost and schedule outcomes, several different paths were considered for carrying forward a project at the Plant Vogtle site.

Following precedent established in the VCM process, the economic evaluation presented in this VCM 17 Report is based on the same major underlying planning assumptions, including fuel forecasts, load forecasts, and generation technology costs, used in the VCM 16 Report. See Sections VI.A.1 and VI.A.2 for additional information on the fuel and load forecasts, respectively, and Section VI.A.4 for a discussion of natural gas-fired technologies considered. Given the importance of establishing the appropriate capacity need for the Project, generation resource planning assumptions were revised for use in these analyses. Section VI.A.5 contains information regarding the updated needs assessment.

The primary driver impacting the economic analysis is an update to the estimate of the capital cost to complete the Project in an environment without the EPC Agreement in place. All associated underlying assumptions, including but not limited to pre- and post-in-service O&M, ad valorem taxes, and nuclear fuel, have been revisited considering the schedule changes. The equity cost of capital applied to Vogtle capital expenditures reflects the terms of the Stipulation, during the construction period of the Project, before returning to the current allowed return of 10.95% through the end of life. The overall marginal cost of capital used in discounting the life-cycle revenue requirements has been reviewed but has not changed from the 16th VCM. Rather than provide analyses based on a single ETC, a range of possible informed cost and schedule outcomes is presented. Given that a range of possible informed outcomes is presented, the delay cases are not presented. See Section IV for additional information regarding the various ETC projections utilized in the economic analyses.

Since none of the range of possible outcomes have the units coming online prior to the deadline needed to receive PTCs, the results presented in the traditional 9-box matrix assume that PTCs are not received. However, given the recent passage of H.R. 1551 in the U.S. House of Representatives (H.R. 1551, 115th Cong. (2017)), sensitivities were developed that assume receipt of 100% of PTCs, regardless of the completion date for the units. Also, although the results presented incorporate only the amount of DOE Loan Guarantees currently secured, based on recent productive talks with the DOE, sensitivities were developed that assume an additional amount of DOE Loan Guarantees. Both incorporation of an extension of the deadline to receive PTCs and additional DOE Loan Guarantees increase the value of completing Plant Vogtle Units 3 and 4 in the economics. Additional information for the PTCs and DOE Loan Guarantees can be found in Sections VI.A.6 and VI.A.7, respectively.

For the first time, the analyses include potential cancellation costs that would not be avoidable in the event the Project is cancelled. These costs were determined by independent expert, Pegasus-Global (see Exhibit 5), and are treated as additional costs on the alternative gas-fired generation in the analyses. The analyses reflect that the cancellation process does not commence until a Commission decision has been rendered, which is estimated to occur in mid-February 2018. Another factor addressed in these economic analyses that has not been captured previously is receipt of the Toshiba Parent Guaranty payments. As shown in the model, it is

assumed that the Toshiba Parent Guaranty payments are received according to the schedule agreed to between the Owners and Toshiba regardless of whether the Project is continued or cancelled.

Georgia Power maintains that the decision whether to proceed with the Project should be based on an Incremental Cost to Complete (marginal) analysis, and sunk costs should be excluded from consideration. However, in addition to the Incremental Cost to Complete analyses presented, the Company also has provided a Total In-Service Cost analysis. This Total In-Service Cost analysis includes the sunk costs and the difference in timing of tax deductions on these sunk costs between a build and cancel scenario. Further explanation of the differences between Incremental Cost to Complete analysis and Total In-Service Cost analysis can be found in Section VI.A.8.

The analyses demonstrate that completing the Project is still an economic option.

A. Analysis Inputs

1. Fuel Forecast

Since adoption of the 2016 IRP, the Budget 2017 fuel forecast was completed and is utilized in the Company's most recent analyses, including the analyses presented in the VCM 16 and VCM 17 Reports.

For natural gas, the Budget 2017 forecast is lower than Budget 2016. Increased production rates and resource supply support a decrease in the forecasted prices.

For coal, the Budget 2017 forecast is lower for both Illinois Basin coal and Powder River Basin coal relative to Budget 2016. An unanticipated increase in production capacity paired with lower demand supports lower price expectations for Illinois Basin coal. A significant decrease in demand contributes to the decrease in forecasted prices for coal from the Powder River Basin.

2. Load and Energy Forecast

Principal assumptions underlying the 2016 IRP Load and Energy Forecast have been updated for Budget 2017. These updates include: (1) an additional 12 months of actual Company

data; (2) updated historical and forecast economic data; and (3) updated electric prices to reflect the changes from the most recent fuel filing. All updates are reflected in the energy and demand forecasts in Budget 2017, Georgia Power's latest budget forecast.

A twenty-year forecast of energy sales and peak demand was developed to meet the planning needs of Georgia Power. The Budget 2017 forecast includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. Compared to Budget 2016 projections, Budget 2017 projected energy sales and peak demand are lower over the forecast horizon due in part to a continued trend of lower usage by customers and the loss of load of two large industrial customers.

Georgia's economy is currently experiencing solid growth, following a slow recovery from the Great Recession. From the end of the recession in 2009 through 2012, Georgia's average annual growth in real output and real personal income was slightly below that of the U.S. and below what occurred in previous expansions. However, since 2013, Georgia's economy has experienced improved growth, with output and income outpacing U.S. growth over this period.

Georgia's economy is expected to show significant strength over the next several years. The state's favorable business environment, including a low cost of doing business, a quality labor force, excellent transportation infrastructure, and a low cost of living relative to those in many other states, will continue to attract businesses and workers. Strong demographic trends are expected to propel Georgia into the top tier of states with respect to economic growth. Over the 2016-2026 period, Georgia's population growth is expected to grow by an average of 1.5% per year, compared to U.S. growth of 0.8% per year. As the economy improves and the population grows, energy sales and the number of customers are also expected to grow.

The Budget 2017 forecast assumptions were developed through a joint effort of Georgia Power and SCS. The forecast was developed through careful consideration and methodical examination of key demographic and economic variables that have historically been significant indicators of energy consumption. Major assumptions include the economic outlook for the U.S. and Georgia, energy prices, weather, and market profiles for class end uses. The economic forecast used in Budget 2017 was obtained from Moody's Analytics, a national provider of

economic data and forecasts. Forecasts from other institutions such as Georgia State University, IHS Markit, and various bank and other publications are used to test the reasonableness of Moody's results. Local area information provided by Georgia Power field personnel is also taken into consideration.

The methodologies used to produce the Budget 2017 forecast are fundamentally unchanged from those used in the Budget 2016 forecast. Short-term energy models are based on econometric regression models developed for the residential, commercial, and industrial energy classes. These models use economic, demographic, weather, price, and other variables. All models are selected based on best fit to recent historical energy use. The long-term energy models used for the residential, commercial, and industrial classes are end-use models. The results of the short-term and long-term models are integrated into a unified forecast. The short-term and long-term governmental lighting and MARTA forecasts use econometric methods, time series methods, and information from Georgia Power field personnel.

The Budget 2017 forecast of peak demand has been reduced compared with the Budget 2016 projection. The decrease reflects a reduction in the energy sales projections for all classes, including the loss of two large industrial loads. Peak demand is lower in all years of the Budget 2017 forecast compared with Budget 2016. The 10-year peak demand compound annual growth rate ("CAGR") is lower in Budget 2017, compared to Budget 2016.

The Budget 2017 residential sales forecast has decreased compared to Budget 2016 due to a number of factors. One factor is that weather-adjusted sales have been relatively flat since the Great Recession, with sales remaining between 25,000 and 27,000 GWh each year. A second factor is that higher fuel prices are expected beginning in 2018, compared to Budget 2016. Energy efficiency is yet another factor. New lighting standards will take effect in 2020 that will reduce energy usage. In addition, the efficiency of water heaters is also expected to increase around the same time as the new lighting standards.

The Budget 2017 commercial energy sales forecast is below the Budget 2016 forecast over the forecast horizon. One reason for this is that, like the Residential class, weather-adjusted sales have been relatively flat since the recession, with energy sales each year in a narrow range

between 32,000 to 33,000 GWh. Other factors behind the lower forecast include slightly slower population growth and a lower commercial building square footage forecast.

The Budget 2017 forecast of industrial energy sales is significantly lower than Budget 2016. As with Residential and Commercial, energy sales have been relatively flat over the past few years, with annual totals remaining in a narrow range between 23,000 and 24,000 GWh since the end of the recession. In Budget 2017, sales from 2016 to 2017 are expected to decline as a result of the loss of two large loads that were not expected in Budget 2016. The strong growth from 2017 to 2018 in Budget 2017 is due to a change in the assumptions of when a very large new customer will come on-line. This customer is currently expected to be operational a year later than was expected in Budget 2016.

Governmental Lighting is undergoing significant change as more and more street lights are changed to Light Emitting Diode (“LED”) lamps, which use much less energy than existing lights. As a result, Budget 2017 energy sales are expected to drop dramatically through 2020. Because such a drop cannot be picked up using econometric models, the forecast is based on information provided by Georgia Power’s field personnel. Budget 2017 was revised upward compared to Budget 2016, to include more up-to-date assumptions about the number of installations expected. As a result, Budget 2017 is declining at a slower rate through 2026, compared to Budget 2016’s expected decline.

The level of the MARTA forecast is essentially the same in Budget 2017 as in Budget 2016 over the forecast horizon. Actual MARTA energy sales in 2016 were significantly lower than expected in Budget 2016. Due to the lower starting point for the growth rate calculation, the growth rate has increased over Budget 2016 in Budget 2017.

The updated forecast has been incorporated in the Needs Assessment and the economic analysis of Plant Vogtle Units 3 and 4 presented in the VCM 16 and VCM 17 Reports. Additional details concerning load and energy forecasts are provided in trade secret Exhibit 8.

3. Carbon Assumptions

Consistent with past VCMs, the Company formally analyzed multiple scenarios of future carbon (or CO₂) pressure. Specifically, scenarios were developed to assess impacts due to CO₂ pressure in the form of \$0, \$10, and \$20 per metric ton of carbon dioxide emitted. These CO₂ views were chosen to span a plausible short-term and long-term range of CO₂ requirements when considering multiple factors, including U.S. economic impact and associated market behaviors. Combined with the three fuel views presented, a range of nine plausible future outcomes is considered. Each of the nine scenarios provides an internally-consistent view of fuel, electricity and other markets in the U.S. economy.

4. Natural Gas-Fired Generation Technology

The combined cycle (“CC”) technology used for the comparison unit in the analysis supporting the VCM process was updated for the 16th VCM. The 17th VCM utilizes the same CC technology. The CC technology was updated from an “F” type machine to an “H” type machine. This annual update is a result of the Company’s planning process, a component of which is the Company’s determination of the most cost-effective combined cycle technology available for commercial deployment for inclusion as a “generic” generating unit to be used in expansion plan modeling and resource evaluations. Recent availability of the “H” machine and national commercial deployment resulted in an update to the Company’s combined cycle technology selection. Compared to the “F” machine, “H” machines are more efficient, larger and more flexible while also being lower cost per unit for both capital and on-going costs, such as future capital and operations and maintenance.

The Plant Vogtle site-specific CCs referenced in the 17th VCM among alternatives considered is also based on an “H” machine but is more expensive than the “generic” discussed above for specific reasons, including higher gas lateral costs than that assumed for the “generic” unit. In addition, given the lack of common infrastructure requirements of nuclear generation and natural gas-fired generation, it was determined that minimal benefit should be assumed from utilizing components already in place at the Plant Vogtle site. For this and other reasons, the Plant Vogtle site is not the Company’s most optimal site for future natural gas-fired generation.

5. Needs Assessment

The Needs Assessment for Georgia Power has been updated for the 17th VCM and incorporates the system target planning reserve margin of 16.25% as approved in the 2016 IRP. The assessment, which can be found in Exhibit 9 reflects updated resource changes such as revised Plant Vogtle in-service dates of November 2021 for Unit 3 and November 2022 for Unit 4 (based on the +29/+29 Case), Budget 2017 load forecast and DSM adjustments, and additions of approximately 1,600 MW of renewable resources as approved in the 2016 IRP. The Company will reevaluate its capacity need requirements in the 2019 IRP, which will be filed in January 2019.

6. Production Tax Credits

Production Tax Credits do not impact the in-service cost of the units, but they do provide benefits to customers through a reduction in revenue requirements beginning when the units go into service and for many years beyond. The Energy Policy Act of 2005 (Section 1306) created a credit for production from advanced nuclear power facilities commonly referred to as Production Tax Credits. To date, these credits have been applied in a well-defined methodology in the Company's VCM filings. The Energy Policy Act of 2005, as it currently stands, requires that to receive the PTCs, the advanced nuclear unit must be online before January 1, 2021. However, H.R. 1551, recently passed by the House of Representatives and pending in the U.S. Senate, will extend the sunset date until the units are operational. As such, sensitivities were developed reflecting receipt of 100% of the PTCs. Further information on PTCs can be found in Section III.E.1.e).

7. DOE Loan Guarantees

The DOE Loan Guarantees provide benefits to customers through lower financing costs during construction and for many years beyond. The benefits associated with this loan are modeled in the economic analysis as established in previous VCM filings.

The Company is currently working with the DOE to expand the amount of DOE funding for the Project. Therefore, additional sensitivities were developed for this 17th VCM to model the

estimated impact to the results given the potential for additional DOE loan(s). Further information on the Company's DOE Loan Guarantee efforts can be found in Section III.E.1.d).

8. *Incremental Cost to Complete Analysis vs. Total In-Service Cost Analysis*

Economic results are presented in Section VI.A.8 for both Incremental Cost to Complete and Total In-Service Cost analyses.

a) Incremental Cost to Complete Analysis

The incremental cost to complete analysis used in this VCM and in all previous VCMs is a marginal cost analytical approach. Marginal analysis is a well-established evaluation method to use for decision-making and has been approved by this Commission for all previous VCMs as well as for many other resource decisions, including those involving potential unit retirements, expansion of renewable energy resources, and spending on energy efficiency programs. A marginal analysis is forward-looking and includes only future costs that the Company can still control. All costs incurred to date are not avoidable and are referred to as sunk costs. Since sunk costs are not avoidable, their exclusion from the forward-looking, marginal analysis is appropriate for decision-making. Because sunk costs are excluded, any income tax implications of these sunk costs are also excluded.

This marginal analysis compares the cost to complete construction, own, operate, and maintain the nuclear units for their 60-year lives versus the cost to cancel the units and then build, own, operate, and maintain an equivalent sized combined cycle natural gas-fired generating plant over the same period.

Because this is a marginal analysis, the Company uses a marginal cost of capital for both the Plant Vogtle Units 3 and 4 costs as well as the comparison generic CC. The debt component of the marginal cost of capital is based on the projected cost of debt for new issuances over the remaining period of the Plant Vogtle Units 3 and 4 spend curve. The equity component of the marginal cost of capital is based on the company's current allowed return on equity ("ROE") of 10.95%. However, NCCR revenue requirements and AFUDC during construction of Plant Vogtle Units 3 and 4 are based on ROEs as agreed to in the Commission order dated January 3, 2017.

b) Total In-Service Cost Analysis

The total in-service cost analysis includes all costs incurred to date and costs projected to be incurred. The total in-service cost analysis includes the same forward-looking costs used in the marginal analysis plus the capital costs incurred to date (sunk costs). While the total in-service cost analysis approach is useful for rate-making purposes once the plant is in service, it is not appropriate for a decision, during construction, on whether to continue construction of the Project where only marginal (or future) costs are avoidable. Under the build Plant Vogtle Units 3 and 4 side of the analysis, these sunk capital costs go into service at COD and are depreciated over the 60-year life of the plant. Under the cancellation side of the analysis, these capital costs are assumed to be treated as a regulatory asset and amortized over a 60-year period to match the expected life of the plant. Please note that the 60-year amortization period for recovery of costs to date under a cancellation scenario is an analysis assumption only. Ultimately, the Commission will determine an appropriate amortization period for these costs, should the Project not proceed. Differences in income tax treatments on these sunk costs based on completing versus cancelling Plant Vogtle Units 3 and 4 are considered in this analysis.

Because this is a total in-service cost analysis, the Company uses an average embedded cost of capital for both the Plant Vogtle Units 3 and 4 costs as well as the alternative CC costs. This is because much of the capital cost of the Project has already been financed at debt rates significantly lower than the marginal cost of debt used in the marginal analysis. The debt component of the embedded cost of capital is based on the Company average cost of debt on both a historical and projected basis. The equity component of the embedded cost of capital is based on the Company's current allowed ROE of 10.95%. However, NCCR revenue requirements and AFUDC during construction of Plant Vogtle Units 3 and 4 are based on ROEs as agreed to in the Stipulation.

The Company believes the Incremental Cost to Complete analysis is the correct methodology to use for analyzing the merits of completing the Project but is providing the Total In-Service Cost analysis as an alternative view that aligns with the projected rate impacts for customers.

B. Alternatives Considered

Presented in Section VI.C are economic analysis results for a range of possible cost and schedule outcomes for completing the Project:

- +20/+20 (Feb 2021/Feb 2022)
- +23/+23 (May 2021/May 2022)
- +29/+29 (Nov 2021/Nov 2022)
- +33/+33 (March 2022/March 2023)
- +41/+41 (Nov 2022/Nov 2023)
- +29/+29 Unit 3 Only (Nov 2021)

Each set of analyses was developed using an Incremental Cost to Complete view and a Total In-Service Cost view.

Additional alternatives were considered including replacement generation from: Renewables, Storage, DSM, and Natural Gas-Fired Generation Technology at the Vogtle Site. A high-level review was completed which demonstrated each potential alternative was unsuitable to support the baseload capacity power needs of Georgia customers. Renewables, Storage, and DSM will continue to have an important role in providing customers with cost-effective, clean, reliable energy; however, due to intermittency, vast land requirements, storage technology maturity, and varying customer usage, these technologies cannot be relied upon to support around-the-clock baseload capacity need. In addition, as explained in Section VI.A.4, two new natural gas-fired combined cycle units at the Plant Vogtle site are less favorable economically than utilizing generic replacement generation assumptions in the analysis. Based on these findings, these alternatives were not further reviewed.

C. Economic Analysis Results

Table VI.C.1a: +20/+20 Case – Incremental Cost to Complete

Relative Savings of the Project versus CC as of February 15, 2018

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$3,207,000,000	\$3,944,000,000	\$5,118,000,000
Moderate	(\$438,000,000)	\$656,000,000	\$1,838,000,000
Low	(\$3,016,000,000)	(\$1,843,000,000)	(\$843,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings for completion of the Project as compared to the gas-fired CC alternative is \$958 million based on the results provided in Table VI.C.1a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.1b: +20/+20 Case Summary – Incremental Cost to Complete

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	\$958,000,000	\$1,072,000,000	\$2,169,000,000	\$2,282,000,000

Table VI.C.2a: +23/+23 Case – Incremental Cost to Complete**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$3,037,000,000	\$3,773,000,000	\$4,948,000,000
Moderate	(\$601,000,000)	\$493,000,000	\$1,678,000,000
Low	(\$3,173,000,000)	(\$1,999,000,000)	(\$997,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings for completion of the Project as compared to the gas-fired CC alternative is \$795 million based on the results provided in Table VI.C.2a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.2b: +23/+23 Case Summary – Incremental Cost to Complete

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	\$795,000,000	\$915,000,000	\$1,981,000,000	\$2,101,000,000

Table VI.C.3a: +29/+29 Case – Incremental Cost to Complete**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$2,801,000,000	\$3,539,000,000	\$4,707,000,000
Moderate	(\$814,000,000)	\$293,000,000	\$1,471,000,000
Low	(\$3,367,000,000)	(\$2,184,000,000)	(\$1,183,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings for completion of the Project as compared to the gas-fired CC alternative is \$585 million based on the results provided in Table VI.C.3a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.3b: +29/+29 Case Summary – Incremental Cost to Complete

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	\$585,000,000	\$716,000,000	\$1,715,000,000	\$1,847,000,000

Table VI.C.4a: +33/+33 Case – Incremental Cost to Complete**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$2,586,000,000	\$3,324,000,000	\$4,489,000,000
Moderate	(\$1,011,000,000)	\$92,000,000	\$1,275,000,000
Low	(\$3,557,000,000)	(\$2,381,000,000)	(\$1,369,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings for completion of the Project as compared to the gas-fired CC alternative is \$383 million based on the results provided in Table VI.C.4a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.4b: +33/+33 Case Summary – Incremental Cost to Complete

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	\$383,000,000	\$514,000,000	\$1,499,000,000	\$1,630,000,000

Table VI.C.5a: +41/+41 Case – Incremental Cost to Complete**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$1,494,000,000	\$2,231,000,000	\$3,414,000,000
Moderate	(\$2,079,000,000)	(\$971,000,000)	\$215,000,000
Low	(\$4,607,000,000)	(\$3,422,000,000)	(\$2,408,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings for completion of the Project as compared to the gas-fired CC alternative is a negative \$681 million based on the results provided in Table VI.C.5a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.5b: +41/+41 Case Summary – Incremental Cost to Complete

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$681,000,000)	(\$550,000,000)	\$371,000,000	\$502,000,000

Table VI.C.6a: +20/+20 Case – Total In-Service Cost**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$2,085,000,000	\$2,882,000,000	\$4,163,000,000
Moderate	(\$1,886,000,000)	(\$696,000,000)	\$591,000,000
Low	(\$4,700,000,000)	(\$3,419,000,000)	(\$2,330,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is a negative \$368 million based on the results provided in Table VI.C.6a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.6b: +20/+20 Case Summary – Total In-Service Cost

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$368,000,000)	(\$251,000,000)	\$859,000,000	\$975,000,000

Table VI.C.7a: +23/+23 Case – Total In-Service Cost**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$1,949,000,000	\$2,746,000,000	\$4,028,000,000
Moderate	(\$2,014,000,000)	(\$824,000,000)	\$466,000,000
Low	(\$4,822,000,000)	(\$3,540,000,000)	(\$2,448,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is a negative \$495 million based on the results provided in Table VI.C.7a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.7b: +23/+23 Case Summary – Total In-Service Cost

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$495,000,000)	(\$373,000,000)	\$707,000,000	\$830,000,000

Table VI.C.8a: +29/+29 Case – Total In-Service Cost**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$1,762,000,000	\$2,560,000,000	\$3,833,000,000
Moderate	(\$2,179,000,000)	(\$975,000,000)	\$306,000,000
Low	(\$4,969,000,000)	(\$3,677,000,000)	(\$2,586,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is a negative \$658 million based on the results provided in Table VI.C.8a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.8b: +29/+29 Case Summary – Total In-Service Cost

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$658,000,000)	(\$524,000,000)	\$491,000,000	\$625,000,000

Table VI.C.9a: +33/+33 Case – Total In-Service Cost**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$1,449,000,000	\$2,247,000,000	\$3,518,000,000
Moderate	(\$2,473,000,000)	(\$1,274,000,000)	\$14,000,000
Low	(\$5,254,000,000)	(\$3,971,000,000)	(\$2,869,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is a negative \$957 million based on the results provided in Table VI.C.9a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.9b: +33/+33 Case Summary – Total In-Service Cost

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$957,000,000)	(\$823,000,000)	\$179,000,000	\$313,000,000

Table VI.C.10a: +41/+41 Case – Total In-Service Cost**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$445,000,000	\$1,243,000,000	\$2,532,000,000
Moderate	(\$3,453,000,000)	(\$2,248,000,000)	(\$958,000,000)
Low	(\$6,217,000,000)	(\$4,924,000,000)	(\$3,821,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is a negative \$1.9 billion based on the results provided Table VI.C.10a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.10b: +41/+41 Case Summary – Total In-Service Cost

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$1,933,000,000)	(\$1,799,000,000)	(\$861,000,000)	(\$726,000,000)

Table VI.C.11a: +29 Unit 3 Only Case – Incremental Cost to Complete
Relative Savings of the Project versus CC as of February 15, 2018
(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	\$736,000,000	\$1,088,000,000	\$1,707,000,000
Moderate	(\$1,087,000,000)	(\$541,000,000)	\$83,000,000
Low	(\$2,359,000,000)	(\$1,774,000,000)	(\$1,248,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is negative \$377 million based on the results provided in Table VI.C.11a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.11b: +29 Unit 3 Only Case Summary – Incremental Cost to Complete

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$377,000,000)	(\$322,000,000)	\$209,000,000	\$264,000,000

Table VI.C.12a: +29 Unit 3 Only Case – Total In-Service Cost**Relative Savings of the Project versus CC as of February 15, 2018**

(In 2021 Dollars)

(Net present value of completing versus cancelling the Project)

Fuel \ CO ₂	\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
High	(\$395,000,000)	(\$15,000,000)	\$660,000,000
Moderate	(\$2,380,000,000)	(\$1,786,000,000)	(\$1,108,000,000)
Low	(\$3,768,000,000)	(\$3,130,000,000)	(\$2,558,000,000)

Positive number means the Project is more beneficial than the gas-fired CC alternative.

The weighted average expected value of the relative savings to customers given the total in-service cost of the Project as compared to the gas-fired CC alternative is a negative \$1.6 billion based on the results provided in Table VI.C.12a. Were the Company able to secure the additional DOE Loan Guarantees previously discussed and/or were the bill extending the PTCs to become law, the values in the boxes and thus also the weighted average would increase as depicted in the summary table below.

Table VI.C.12b: +29 Unit 3 Only Case Summary – Total In-Service Cost

	Current State	Current State + Add'l DOE Benefits	Current State + PTC Extension	Current State + Add'l DOE Benefits & PTC Extension
Matrix Average (\$M/2021\$)	(\$1,609,000,000)	(\$1,553,000,000)	(\$1,015,000,000)	(\$959,000,000)

Economic Analysis Conclusion / Summary of Results:

In summary, these analyses support continuation of the Project when taken in consideration with the qualitative factors discussed elsewhere in this VCM 17 Report.

VII. NEW PROJECT CONFIGURATION

A. Revised Ownership Participation Agreement

Recognizing that completing the Project in the absence of the EPC Agreement will entail different risks and may require additional decision-making points for the Owners, the Owners agreed to revise the Project Ownership Participation Agreement to establish additional conditions that will require Owner approval.²⁹ Ninety percent ownership approval is required to proceed with the Project following a “Project Adverse Event,” which would include (1) Toshiba’s default under the Toshiba Parent Guaranty Settlement Agreement, (2) the bankruptcy of the prime contractor, Bechtel, or (3) the failure of the Commission to approve Georgia Power’s share of the proposed revised cost forecast and construction schedule, or a finding by the Commission that any part of Georgia Power’s capital investment or associated financing costs (other than already provided in the Stipulation) are not recoverable or will be presumed non recoverable.

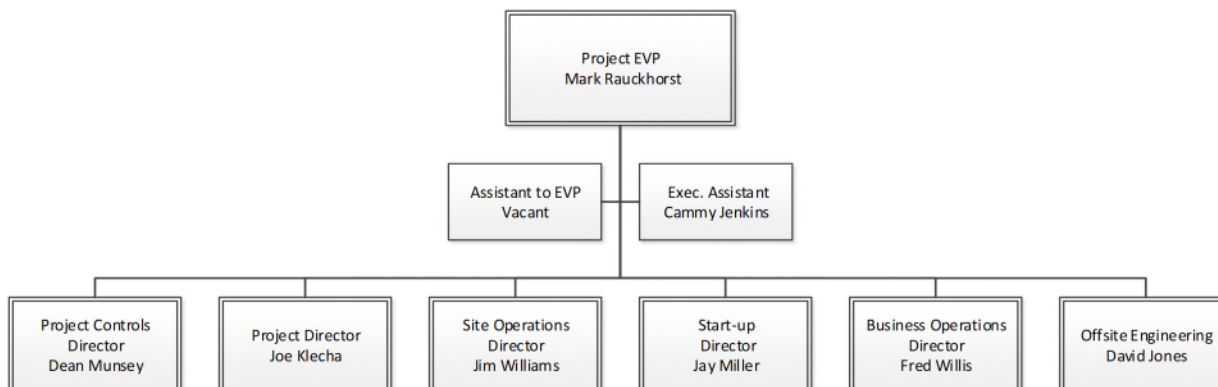
If the Commission determines that a portion of Georgia Power’s costs are unreasonable, or imprudent or otherwise unrecoverable from customers, then it would follow that the similar share of the non-Georgia Power Owners’ costs would correspondingly be unreasonable, or imprudent or should be otherwise unrecoverable from customers. But for the non-Georgia Power Owners, there is nowhere else to turn but to their customers. Rather than proceed to that result, the non-Georgia Power Owners, indeed all Owners, would rather stop and never incur those unreasonable or imprudent costs that would otherwise be passed on to customers. The revisions in the Ownership Participation Agreement, including but not limited to this particular provision, were a specific condition on which the Owners moved forward and without which they would not have been able to move forward.

²⁹ A copy of the revised Project Ownership Participation Agreement term sheet is attached as Exhibit 10.

Other decisions that would require ninety percent ownership approval include the appointment of a new agent, a change in the prime contractor Bechtel, or the decision to renew the COL or set a timeframe for decommissioning. Sixty-seven percent ownership approval would be required to materially amend a material Project contract with Southern Nuclear, Westinghouse or Bechtel, increase the construction budget or schedule from those set in August 2017, or defer or discontinue the Project, except following a Project Adverse Event or unless ordered by the Commission or the NRC. A simple majority vote of the Owners would be required to pursue or settle litigation or other formal dispute resolution of a material Project dispute. The non-Georgia Power Owners agree that their sole recourse against Southern Nuclear or Georgia Power is their removal as agent. Revision of the Ownership Participation Agreement was an Owners' condition without which the Owners would not have agreed to go forward. The revised Project Ownership Participation Agreement also provides the Owners with specific access to Project information.

B. SNC's Proposed Management Structure

Under the new Project configuration, SNC, as agent for Georgia Power, is the main Project contractor with ultimate responsibility for successful completion of the Vogtle Project. The SNC organizational structure has been aligned around an integrated project execution focus, with a singular point of accountability for all SNC and contractor resources. As shown in the figure below, Mark Rauckhorst, the Vogtle Project Executive Vice President, will oversee all major functional areas required for construction, testing and startup:



In addition to the organizational efforts within SNC, the Company received bids from both Fluor and Bechtel to serve as the construction contractor and, upon careful review of the

bids and discussions with both firms, the Company selected Bechtel as the construction contractor. Given the experience Bechtel has on the Project, an efficient transition to a single construction contractor is expected, with minimal disruption on the Project. Under the Services Agreement, Westinghouse will continue to provide engineering and procurement support as well as access to the AP1000 technology. The Company will continue to work closely with SNC to provide oversight and to ensure quality and compliant construction.

There are several important changes to the Project management structure worth highlighting. First, there will be a full-time project executive on-site to represent Bechtel. Having that executive on-site gives SNC the ability to leverage the full contractor organization in terms of planning and execution. All contractor personnel, however, will report up through SNC leadership; no contractor personnel will be placed in senior leadership positions on the Project.

Further, SNC has created a separate project controls group which reports to management independent of the project execution organization. The organization reports to Mark Rauckhorst, and is tasked with ensuring the proper processes and structures are in place to manage the project scheduling, cost, change control, reporting, and risk management. The project execution organization, reporting to the Project Director, Joe Klecha, uses the schedule created by project controls to ensure engineering and design are complete well in advance of the need for construction. The project execution team will finalize detailed work plans 8-12 weeks prior to construction needs utilizing the construction work management process.

Finally, SNC will leverage personal accountability to help project execution and improve schedule adherence. By including area managers in the detailed scheduling process, SNC will ensure the functional areas take accountability for schedule adherence and execution.

C. Bechtel as Construction Contractor

The Owners have selected Bechtel to manage construction on the Project. As demonstrated by Bechtel's performance to date at the Project, Bechtel brings to the Project a well-qualified, talented team with strong leadership and senior-level engagement. Bechtel has a strong relationship with the building trades. Bechtel has developed a comprehensive, risk informed plan to achieve success on the Project and has reviewed and substantiated portions of the Southern Nuclear ETC. The Bechtel Agreement aligns Bechtel with the Owners on the goals

of completing the Project in the most efficient manner. The Bechtel Agreement is a reimbursable contract with a performance component, under which Bechtel accepts some risk if the Project cannot meet certain cost and schedule goals. Bechtel will receive a base fee and may earn an “At Risk Fee” if the Project’s schedule and cost performance warrant it.

D. Summary of Risks and Benefits of Project Continuation

Consistent with the Company’s April 2016 Supplemental Information Report, the Project continues to offer the same long-term benefits to the Owners’ customers and the state of Georgia. All of the Owners continue to actively support this Project, have approved its revised budgets and schedules, and continue to recognize the value of this Project to Georgia’s future. The completed Vogtle units will provide a new safe, clean, reliable and affordable source of electricity for the state of Georgia for the next 60 and possibly 80 years. This Project remains the most important infrastructure project currently under way in Georgia, providing thousands of construction jobs and approximately 800 permanent careers once the new units come online. The Project will support the state’s future economic growth and will have a direct economic benefit not only for the state’s current electric customers, but also for those businesses or customers looking to expand or relocate in Georgia.

As discussed in detail in the Company’s April 2016 Supplemental Information Report, the Owners anticipated challenges in building the first new U.S. nuclear units in more than 30 years, risks that were highlighted by both the Company and the Construction Monitor during the Vogtle Certification proceeding in 2009. As previously discussed, many of those risks were realized and the Company proactively managed those risks to avoid significant impact to customers.

There are significant risks that the Commission must consider both in the case of proceeding with construction and in the case of cancellation. It is not possible to create an all-inclusive list of the risks facing the Project; however, we can provide some details concerning the risks that the Commission should consider. There are many risks to the assumptions the Owners made when recommending that this Project go forward. As discussed earlier in this Report in Section II, these include:

1. *The risk that Toshiba will be financially unable to meet the payment obligations of the Toshiba Parent Guaranty*

During the negotiations leading to the EPC Agreement, the Owners insisted that the counterparties provide security in the form of a parent company guaranty. At that time, the Owners were not aware of any reason that Toshiba would not be able to fund any shortfalls due to the Owners under the EPC Agreement. Nonetheless, the Owners further insisted on the requirement that Westinghouse produce letters of credit if Toshiba's credit rating fell below a preset threshold. Following the downgrade of Toshiba's credit rating in December 2015, Georgia Power, on behalf of the Owners, demanded that Westinghouse post letters of credit totaling \$920 million. Georgia Power holds these letters today as security against the risk that Toshiba does not pay the agreed-to amounts under the Toshiba Parent Guaranty Settlement Agreement.

However, as indicated in several recent public announcements, Toshiba has encountered financial difficulties stemming from write-downs associated with Westinghouse, as well as the accounting irregularities that Toshiba reported in 2015. These difficulties could ultimately impact Toshiba's payments of the amounts due under the Toshiba Parent Guaranty Settlement Agreement. If Toshiba is unable to pay the amount it owes under the Toshiba Parent Guaranty Settlement Agreement, this amount will not be available to offset the increased costs of construction under the new Project organization. The Owners consider non-payment of the Parent Guaranty to be a fatal event and have agreed that they would stop the Project unless 90% of the Owners vote to continue.

2. *The risk that WEC will not meet its obligations under the new Services Agreement*

The risk that Westinghouse does not perform under the Services Agreement is a low probability but would have a high impact on the Project. WEC holds the intellectual property ("IP") proprietary rights to the AP1000 technology, and while the Owners have access to that IP, it would be very hard to continue without the expertise of WEC engineers. The Services Agreement protects against a risk of nonperformance, and it is in WEC's financial self-interest to perform under the Services Agreement, but some risk of nonperformance must be recognized.

3. *The risk that the labor force and craft will be unable to maintain their productivity improvements*

This risk was identified as project execution risk and it will continue throughout the life of the Project. Simply stated, the project execution risk encompasses the risk that the Project is unable to execute with the resources or in the timeframe that is accounted for by the current projections. Possible manifestations of this risk include an inability to reach forecasted production rates or sustain the productivity rates that are incorporated into the Southern Nuclear ETC. The risk that the Project cannot execute in accordance with the forecasted rates of production comprises a significant project execution risk. This risk also encompasses higher than anticipated rates of rework, or greater than expected design changes. Personnel factors, such as not having sufficient field engineering resources available for a period of time, also fall into project execution risk.

The Company has considered Project costs over a wide range of performance factors, which account for the possibility that production rates and productivity will be lower than the current forecast. The Kenrich ETC and the PwC report provide sensitivities on these considerations. While the Company has tried to develop the best possible estimate, the possibility of lower than expected productivity remains. Prior to Westinghouse's rejection of the EPC Agreement, the primary impact of this risk to the Company was the risk that the schedule would be extended. As the Project proceeds without the EPC Agreement, the impact to the Owners will be greater because the Owners will have to pay the additional labor cost necessary to complete the work in addition to costs incurred as a result of the schedule extension.

4. *The risk that the Project will be unable to continue to meet FOAK challenges*

As with any FOAK project, a broad range of FOAK execution risks remain. One FOAK risk unique to this Project is the possibility of a delay to fuel load as a result of ITAAC closure, licensing challenges, or inadequate quality assurance documentation. One possible source of a delay is challenges in closing one or more ITAAC to enable fuel load. While 10 CFR Part 52 has limited this risk, it remains possible that it will take the NRC more time than currently anticipated to approve the fuel load, either due to an issue involving ITAAC or other issues. In

addition to the closure of all ITAACs, the possibility of emergent licensing and design issues exists. There is also a potential risk of discovery of an issue that calls the quality assurance pedigree of a component into question. In this event, the nonconformance with quality assurance requirements must be dispositioned, which could result in a decision to use the component as-is or to remove and replace the component. Late discovery of quality assurance problems could delay fuel load while the problems are resolved.

SNC has worked diligently to establish alignment with the NRC to minimize the time between the closure of all ITAAC items and the NRC's 10 CFR 52.103(g) finding authorizing fuel load. SNC has also worked with the NRC to determine ahead of time what the NRC will accept as sufficient information to close an ITAAC through the Uncompleted ITAAC Notification ("UIN") process. Also, SNC has maintained rigorous oversight of the quality assurance program at all levels of the Project.

5. *The risk that Congress will not extend the PTCs*

The Vogtle Project will qualify for the advanced nuclear facility federal income tax credit of 1.8 cents for each kWh of electrical energy produced and sold to third parties for an eight-year period following the placed in-service date of the plant, provided the plant is placed in service prior to January 1, 2021, subject to certain limits. The Company is actively supporting bipartisan legislation introduced and passed in the United States House of Representatives and now pending in the United States Senate that would allow the Vogtle Project to continue to qualify for advanced nuclear PTCs since it is now clear that the units will be placed in service after January 1, 2021. The failure of Congress to extend PTCs will have a material adverse effect on the economics of going forward with this Project.

6. *The risk that the DOE will be unwilling to extend and expand the Loan Guarantee*

The Company has already secured DOE Loan Guarantees that are expected to save customers approximately \$375 million. In addition, the Company is engaged with the DOE to expand the current capacity of the original commitment. Should the capacity be expanded, the Company conservatively estimates that for every additional billion dollars secured, customers

will save an additional \$80 million. If the DOE does not agree to expand the current capacity of the loan guarantee, the presumed benefits of going forward will diminish.

Several other risks discussed during the Certification proceedings have been somewhat mitigated by the progress made to date, but nonetheless remain:

7. Procurement Risk

Procurement risk encompasses problems such as a major defect in a long-lead procurement item or the necessity for a design change to a procurement item, which would affect its price or the timing of its delivery. Another possible risk is that design finalization does not occur in time to procure items to meet construction need. Georgia Power and Southern Nuclear have continuously monitored key procurement items over the duration of the Project. While there continues to be a risk related to procurement for the project moving forward, the potential impact of this risk has been greatly reduced by the completion of fabrication and delivery of most long-lead items to the site. These items include Unit 3 & 4 reactor vessels, steam generators, accumulators, core make-up tanks, pressurizers, and all turbine/generator equipment. Procurement oversight has involved enhanced inspection programs, visits to fabrication facilities for procurement items, and, in some cases, the establishment of an on-site resident at certain fabrication facilities. Southern Nuclear will continue to maintain a robust oversight program for procurement and will add resources to oversee vendors who are not performing to expectation or where additional oversight resources are otherwise deemed appropriate.

8. Unidentified Scope Risk

Unidentified scope risk includes the risk of work that must be performed to finish the Project that is not included in SNC's ETC. Examples include design changes that cause the need for rework or that make performing the work more difficult than the SNC ETC currently projects. These changes could result from constructability concerns or because of NRC-driven design changes. Another example of unidentified scope would be a difference in interpretations of the applicable codes with the NRC that required the Project to perform the work differently, undertake more extensive inspections, or redo already completed work.

SNC and Georgia Power will exercise oversight over the design change process with a goal of ensuring that certified-for-construction drawings and work packages are available, with all identified design changes processed and reviews for constructability complete, well in advance of construction need. The Company will also take a disciplined approach to design changes and engage actively with the NRC. Unfortunately, even with active management by the Company, the risk of unidentified work scope from factors that have not been anticipated cannot be eliminated entirely.

As explained above, project execution risk covers the risk that Project management is unable to execute to the forecasted production rates and productivity. Causes for this risk include lack of available work fronts, lack of available field resources, or an overestimation of the rate at which the work can be completed. Unidentified scope risk includes changes that are made to the amount of work that must be completed that are not currently included in the Southern Nuclear ETC.

9. Stranded Technology Risk

This risk speaks to the possibility that only a small number of AP1000s come online worldwide. If only a few AP1000 units are built worldwide, future procurement of replacement components and engineering services could become more costly or difficult than currently expected. As a result, the Company's forecasts for long-term O&M and recurring capital budgets may need to be increased to maintain the plant in the future.

The number of AP1000s that are operated worldwide is outside the Company's control. The Company can engage in early procurement for replacement parts and can undertake a long-term engineering support contract with Westinghouse to mitigate this risk; however, the pricing of these contracts may ultimately depend on how many other utilities require services for the AP1000. The ability to obtain these services is also dependent on the long-term viability of Westinghouse or a subsequent owner of the technology, which is outside of the Company's control.

10. Fuel Risk

The fuel risk accounts for the volatility of fuel prices over the sixty plus year life of the Project. Cancelling the Project in favor of a natural gas combined cycle increases the exposure of customers to fluctuations in natural gas prices as well as natural gas supply problems. While the price of nuclear fuel has historically been more stable than natural gas, there is also uncertainty regarding the future price of nuclear fuel. Continuing the Project limits the exposure of customers to natural gas prices but exposes customers to future fluctuations in nuclear fuel prices.

The Company views continuing the Project as a significant hedge against future natural gas prices. The Company manages the risks associated with dependence on natural gas by maintaining a diverse generation portfolio that is resilient against price changes in a single commodity. The Project meets this criterion.

11. Risk of Carbon Emissions Controls

Unlike the procurement risk, scope change risk, and technology risk, the carbon risk has not been mitigated since the Project began. Georgia Power has recognized, and continues to recognize, that there is considerable uncertainty regarding the future of carbon regulation. One of the most significant benefits of nuclear power is its ability to meet base load demand without the levels of carbon dioxide emissions associated with fossil fuel facilities (which includes natural gas-fired generation plants). The Company cannot predict what price, if any, will ultimately be applied to carbon dioxide emissions, or when any price that is applied will take effect.

As described in more detail in Section VI, the Company's economic analysis presents scenarios for \$0, \$10, and \$20 per metric ton of carbon dioxide emitted. These scenarios provide a wide range of carbon dioxide scenarios for consideration by the Commission.

12. Testing/Startup Risk

The Owners and SNC are closely monitoring the four AP1000s currently under construction in China. Two of the four units in China are expected to load fuel in the next few months. The Project will address any problems that the testing of the Chinese units reveals to

avoid similar problems at Plant Vogtle. However, there are significant differences between the Chinese AP1000s and the Project, so the possibility of additional or different testing and startup problems at Vogtle remains.

This risk encompasses the possibility that the AP1000 reactor does not function as designed or that hot functional or low power testing reveal problems that must be addressed before the Project can be placed in service. The Project will be the first AP1000s to operate in the United States and will undergo an extensive testing regime. If the testing reveals a problem that requires extensive design or engineering work, additional delays to the in-service dates could result.

Plant Vogtle Units 3 and 4 are now the only two AP1000s under construction in the United States. Previously, Southern Nuclear worked with SCE&G to determine lessons learned and to handle licensing issues such as the submission of License Amendment Requests to the NRC. In the absence of SCE&G, the burden and cost of these amendment requests will fall entirely onto Southern Nuclear. Also, SCE&G's decision to abandon V.C. Summer Units 2 and 3 could affect procurement costs. Finally, since the Vogtle Project is the only AP1000 project continuing construction in the United States, the risk of the AP1000 being stranded technology is increased by SCE&G's decision to cancel.

These risks discussed above include some of the risks that the Owners have considered in reaching the decision about how to proceed. As with any endeavor, the future is uncertain, and it is likely that other risks that are not currently known will manifest themselves.

E. V.C. Summer Abandonment Impact to Project

The Owners have also informally discussed the Westinghouse bankruptcy proceedings with SCE&G on an as-needed basis. The Vogtle and V.C. Summer projects both have representation on the creditor's committee in the Westinghouse bankruptcy proceeding. On July 31, 2017, SCE&G announced that it was ceasing construction of the V.C. Summer project and, on August 1, 2017, SCE&G submitted an application to seek approval of its abandonment plan with the South Carolina Public Service Commission (which it has since withdrawn pending South Carolina legislative review), concluding that it would not be in the best interest of its customers and other stakeholders to continue construction of the project. In arriving at its

decision to cease construction of the V.C. Summer project, SCE&G cited the additional costs to complete the units, the uncertainty regarding the availability of PTCs for the project, the amount of anticipated guaranty settlement payments from Toshiba, and other matters associated with continuing construction, including the decision of the co-owner of the project, Santee Cooper, to suspend construction of the V.C. Summer project.

Although the Vogtle Project also faces many of the same risks that led the V.C. Summer Owners to cancel the plant, the Owners are better positioned to continue the Vogtle Project. First, the Vogtle Owners were able to secure \$3.68 billion in the Toshiba Parent Guaranty Settlement Agreement whereas SCE&G and Santee Cooper secured approximately \$2.2 billion. Georgia Power has approximately three times as many customers as SCE&G. While SCE&G customers have seen a rate impact of approximately 18% on average to cover the financing costs associated with the construction of V.C. Summer, Georgia Power customers have seen a 5% impact on average. Finally, where SCE&G had only one partner that held a 45% interest in the V.C. Summer project, Georgia Power shares ownership of the Vogtle Project with three other entities, OPC (30% interest), MEAG (22.7% interest), and Dalton (1.6% interest). Thus, the Vogtle Owners are better positioned to continue construction of the Vogtle Project.

VIII. REQUEST TO VERIFY AND APPROVE COSTS INCURRED DURING THE REPORTING PERIOD

A. Highlights

- **Georgia Power and SNC as agent for Georgia Power, are fulfilling their commitment to safety, quality and compliance.**

During the Reporting Period, approximately 8.1 million work hours were performed safely with no lost time injuries.

The Company received one Notice of Violation and remained in favorable standing with the NRC as indicated by its green status under the NRC's Construction Reactor Oversight Process.

- **Georgia Power is requesting verification and approval of \$542 million of actual expenditures incurred during the Reporting Period.**

17th VCM Expenditures	
<i>Dollars in Millions</i>	
EPC	43
Interim Payments & Liens	414
Quality Assurance, Compliance and Operations & EPC Scope Change	69
Ad Valorem Tax	14
Transmission	2
Total 17th VCM Expenditures	<u>\$542</u>

Additional detail for the costs comprising the \$414 million of Interim Payments & Liens incurred as a result of the Westinghouse bankruptcy during the Reporting Period is provided below:

Interim Payment and Liens - 17th VCM	
<i>Dollars in Millions</i>	
Accruals	\$92
Fluor Lien Discharge	74
Fluor Post-Petition	68
Fluor Pre-Petition	12
Westinghouse Post-Petition	161
Westinghouse Post-Petition Sub Contractor	7
Total Interim Payments & Liens	<u>\$414</u>

- **The Project continues to progress and achieved significant milestones.**

As discussed in more detail in response to question 12 below, construction continued to progress with several key components being installed, including the Unit 3 Reactor Coolant Loop Piping and Unit 3 Steam Generator B.

As the Project prepares for operations, key milestones were accomplished, with 19 candidates successfully completing the NRC Initial License Training exam and turnover of the first four Project Boundary Identification Packages (“BIPs”).

B. Stipulated Questions

As agreed in the Stipulation that was incorporated into the Certification Order, Georgia Power responds below to the 15 specified items in the order in which they appear in Section 2(d)(1-15) of the Stipulation. In this VCM 17 Report, and in accordance with the Commission's Order on the Ninth/Tenth VCM Report ("9th/10th VCM Order"), Georgia Power has omitted Items 4, 10 and 13.

1. The reasons for any additional change in the estimated costs of the units since the process began.

This is answered elsewhere and throughout the Report.

Table 1.1

Vogtle 3&4 Project
Georgia Power Company Cost - **Subject to Commission Verification and Approval**
Total Project Costs ⁽¹⁾

Construction & Capital Cost	Total Current Forecast (\$ millions)
Original EPC ⁽²⁾	\$3,257
Interim Payments & Liens ⁽³⁾	493
New Site Forecast EPC	
Engineering Contractor	545
Procurement	938
Contract Construction	1,374
Construction Support	388
Project Management	478
	<u>3,723</u>
Owners Cost	996
Ad Valorem Tax	273
Transmission Interconnection	61
Test Fuel Offsets	<u>(33)</u>
	1,298
Total Construction & Capital Cost ⁽¹⁾	\$8,771

Vogtle 3&4 Project
Georgia Power Company Financing Cost - **Recovered Pursuant to O.C.G.A. 46-2-25 (c.1)**
and the January 3, 2017 Order Adopting Stipulation
Total Project Financing

Project Schedule Financing ⁽⁴⁾	Total Current Forecast (\$ millions)
Return on CWIP in Rate Base ⁽⁵⁾	\$2,862
AFUDC - Accrued on CWIP Above Original Certified Cost	428
AFUDC - Accrued through December 2010 and Related Return	<u>109</u>
Total Project Schedule Financing	\$3,399

Total Capital Cost and Financing	\$12,170
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Footnotes:

1. Total Current Forecast includes project to date actuals of \$4.444 billion through June 30, 2017 and forecasted costs for July 1, 2017 through November 2022. \$542 million was incurred during the VCM 17 reporting period of January 2017 through June 2017.
2. Includes payments under the original EPC Agreement and EPC Scope Change costs.
3. Includes liens and liabilities under the Interim Assessment Agreement.
4. The financing costs are based on a spend curve that assumes the scheduled receipt of the Toshiba Parent Guarantee payments.
5. NCCR will only be collected on the certified capital cost of \$4.418 billion per Order dated January 3, 2017.

2. A description of any cooperative actions between other builders of nuclear units in the southeast to address labor, crafts, engineering and management requirements.

As reported in previous VCM reports, during the Reporting Period, SNC continued to actively participate as a member of APOG LLC (“APOG”) with other members, Florida Power & Light, NextEra, Duke Energy, and South Carolina Electric and Gas Company (“SCE&G”) to support multiple engineering, licensing, quality assurance, operational readiness and training initiatives. After the Reporting Period, in light of the announcement by Duke Energy on August 25, 2017, requesting that the North Carolina Utilities Commission approve its decision to cancel the Lee Nuclear Project and SCE&G’s announcement on July 31, 2017, that it would cease construction on V.C. Summer, APOG participation will occur on a more limited basis.

During the Reporting Period and to the extent allowed by the EPC Agreement, the Company engaged with SCE&G on the peer-to-peer level in each functional area of the oversight organization to ensure alignment and to utilize lessons learned and best practices. For example, SNC and SCE&G often participated in joint quality assurance audits and oversight surveillances of the Contractor. SNC and SCE&G construction personnel shared construction lessons learned and best practices. Engineering and licensing personnel from the two companies communicated regularly to ensure alignment on resolution to standard design challenges, and also communicated potential impacts to licensing requirements. Collaboration with the SCE&G ITAAC team was ongoing during the Reporting Period and resulted in identification and sharing of best practices to support implementation of an effective and streamlined ITAAC program. SNC and SCE&G collaborated as necessary with regard to the respective cyber security programs being developed and implemented by the Contractor. The Operational Readiness organizations for SNC and SCE&G collaborated on the development of operations, maintenance and technical training programs, which included sharing lesson plans, task lists, qualification cards and providing joint support for APOG. Additionally, during the Reporting Period, a cross-functional team, including WEC, SCE&G and SNC personnel, was formed to ensure configuration management of the plant and simulator, as well as efficient implementation of the Instrumentation and Controls design upgrade from Baseline 7 to Baseline 8. As the Project transitioned from WEC to SNC as general contractor, the Company and SCE&G continued to collaborate to support project activities until SCE&G announced its decision to cease construction of the V.C. Summer units. These activities included high-level discussions with SCE&G on the development of a revised estimate-to-complete, including the engineering, procurement and construction inputs used for the analysis.

3. An explanation of how the indices used in the EPC contract are tracking.

There has been no change in the status of this item since the Eighth VCM Report.

4. Omitted per 9th/10th VCM Order.

5. The status of the Company's loan guarantee application at the Department of Energy and to the extent that application is granted, then the Company shall also report on the impact it has or would have on the final expected in-service cost of the units.

Available	Received	Remaining
\$3.46 Billion	\$2.63 Billion	\$0.83 Billion

The DOE Loan Guarantee provides benefits to customers through lower financing costs during construction and for many years beyond. The Company is in discussions with the DOE to expand the current capacity of the original commitment. Additionally, the Company has entered into a third amendment to the DOE Loan Guarantee Agreement. Under the terms of the Amendment, the Company will not request any advances until the Company has made a determination to continue construction of the Vogtle Project and delivered an updated cost, schedule and other information to the DOE.

6. Whether the Company is using trust preferred financing and the impact it has or would have on the expected in-service cost of the units.

There has been no change in the status of this item since the Sixth VCM Report.

7. The extent to which the Company is using short term debt and the impact it has or would have on the expected in-service cost of the units.

There has been no change in the status of this item since the Third VCM Report.

8. An update of the estimated in-service cost and projected date of commercial operation of both units.

The updated in-service Total Construction and Capital Cost forecast is \$8.771 billion and the in-service dates for Vogtle 3 and 4 are November 2021 and November 2022, respectively.

9. A description of all major sources of changes (both increases and decreases) to the in-service cost and sources of change in commercial operation dates, if any.

This is answered elsewhere and throughout the Report.

10. Omitted per 9th/10th VCM Order.

11. The status of all other significant permits and licenses required from other governmental agencies.

All other required permits and licenses have been approved or are on track to be approved to meet construction need dates as shown in the Permits Update filed monthly with the Commission. The status for the Reporting Period can be found in the June 2017 Monthly Status Report.

12. The status of Quality and Compliance, Engineering, Procurement, Construction and Start Up.

A. Quality and Compliance

- The Company continued to provide oversight of the Contractor, actively addressed issues and concerns, and provided guidance and support to the Contractor, as necessary.
- The Company completed 610 oversight surveillances during the Reporting Period.
- Lessons learned continue to be captured during first time evolutions for Unit 3 and incorporated into Unit 4 execution.
 - Modularization of the Unit 4 Annex Building steel floors allowed for more efficient process in installing the supplemental steel that will support piping, HVAC equipment, electrical conduit and cable trays.
 - Large structural steel modules were painted in sections during pre-assembly to progress with additional work fronts after installation.
 - Construction joint prep has been simplified to prevent time consuming re-work.
- The Company continued to assess and allocate resources necessary to perform its oversight for optimization of project progression.

B. Engineering

- AP1000 Commercialization efforts implemented for non-safety related construction in the Turbine Island and Balance of Plant areas.
 - Field Change Process (“FCP”) was developed and currently being implemented which:
 - Provides a streamlined method to execute design changes within the non-safety related portions of the plant.
 - Reduces engineering resources and improves engineering response time
 - The FCP has processed approximately 300 field changes.
 - Standard Construction Datasheets have been developed which:

- Summarizes critical attributes defined by engineering for construction execution and inspection.
- Replaces previously developed inspection plans, resulting in simplified, standardized work packages.
- The following design engineering was completed during the Reporting Period:
 - Turbine Island, Annex, Radwaste and Diesel Generator Buildings electrical cable tray, modeled conduit and associated supports.
 - Passive Containment Cooling Ancillary Water Storage Tank piping and hurricane missile protection.
 - Completion of raceway optimization to improve raceway design layout and reduce supports in the Annex, Turbine Island, and Auxiliary Building at elevation 66 feet 6 inches.

C. **Procurement**

- The Company continued its oversight of the fabrication of major equipment at international and domestic vendor locations. Challenges associated with design and/or testing are closely monitored by the Company to ensure those are adequately resolved before installation.
- The Company remained focused on its oversight of safety-related commodity vendor locations. Oversight of the following commodities occurred during the Reporting Period: reinforcing steel, structural steel, embeds, pipe supports, piping penetrations, spools, cable tray, cabling, cranes, pumps and valves.
- The Company and Contractor's Procurement Engineering Organizations facilitated:
 - Utilization of Generic Commercial Grade Dedication Plans for bulk commodities to help reduce delays in the procurement process.
 - TEKLA modeling for interference checks prior to the need for fabrication for Containment, Annex, Radwaste, and Diesel Generator Buildings rebar.
 - Process mapping of the procurement system to help identify gaps.

Component	Unit 3 Status	Unit 4 Status
Accumulator Tanks	Installed	On-site
Core Makeup Tanks	On-site	On-site
Deaerators	Installed	On-site
Diesel Generators	On-site	On-site
Integrated Head Package	On-site	On-site
Main Step-up Transformers	Installed	On-site
Main Turbine Generator	Installed	On-site
Moisture Separator Reheater	Installed	On-site
Passive Residual Heat Removal Heat Exchanger	On-site	Fabrication Complete
Polar Crane	Fabrication Complete	In Fabrication
Pressurizer	On-site	On-site
Reactor Coolant Loop Piping	Installed	On-site
Reactor Coolant Pumps	On-site	3 of 4 Delivered
Reactor Vessel	Installed	On-site
Reactor Vessel Internals	On-site	In Fabrication
Reserve Auxiliary Transformers	Installed	Installed
Squib Valves 8"	In Fabrication	In Fabrication
Squib Valves 14"	On-site	On-site
Steam Generators	1 of 2 Installed	On-site

- Major equipment delivered during the Reporting Period includes: Unit 3 and Unit 4 14-inch Squib Valves, Unit 3 Passive Residual Heat Removal Heat Exchanger, three of four Unit 4 Reactor Coolant Pump.

Modules

Unit 3 Shield Building

- There are 155 of 167 panels on-site (87 of 167 Unit 4 Shield Building panels have also been delivered).
- NNI completed building expansion and fabrication of air inlet and tension ring mock-ups and commenced panel fabrication with no quality issues.
- IHI commenced fabrication of the Unit 3 Shield Building roof steel panels.

Unit 3 CB20 Passive Containment Cooling System (“PCS”) Tank Module

- Commenced fabrication of module panels at Vigor.
- 21 of 112 panels delivered during the Reporting Period.



Photo 1 – Unit 3 CB20 PCS Tank Panels

Unit 4 CA02

- Completed upending submodules.
 - 4 of 5 sub-modules upended
 - 5th sub-module will be up-ended inside containment
- Seam welding and outfitting is complete.

Unit 4 CA03

- Completed upending and seam welding on all 17 sub-modules.
- Outfitting of the module commenced (leak chase, piping, pipe, angle splices, tube steel).

Unit 4 CA01 (Sub-assembly 7)

- Pressurizer compartment assembly continues in MAB.
- Seam welding complete.
- Outfitting continues (Overlay plates, direct weld attachments, b-plates).

Aecon

- Continued progress on Nuclear Island safety-related mechanical modules.
 - Delivered Unit 3 Q305 Containment Isolation Valve and Unit 4 Q223 Direct Vessel Injection Valve module.
 - Completed fabrication of Unit 3 KB36 Passive Containment Cooling System Pump and Valve module.
 - Continued fabrication of Unit 3 Q601 and Unit 3 Ring Girder.

D. Construction:

Unit 3 Nuclear Island

- Significant progress continued during the Reporting Period.
 - Installed approximately 390 tons of rebar.
 - Placed approximately 2,519 cubic yards of concrete.
 - Installed approximately 4,044 linear feet of large bore pipe and pipe supports.
- Set sub-module CA02-05 inside containment and completed welding.
- Placed concrete inside CA01 Steam Generator B compartment walls to elevation 152 feet 10.5 inches.
- Installed and welded out the east side and west side reactor coolant loop piping inside containment.
- Installed rebar and placed concrete to elevation 105 feet 2 inches on the south and east side of containment.
- Placed concrete inside the CA05 module from elevation 87 feet 6 inches to 105 feet 2 inches inside containment.
- Installed rebar and placed concrete in the refueling cavity to elevation 95 feet.
- Installed rebar and placed concrete to elevation 98 feet 6 inches in the north end of containment.
- Set wall module CB26 for the Chemical and Volume Control (“CVS”) room wall in the north end of containment.
- Set floor module CA32 at elevation 105 feet 2 inches in the north end of containment.
- Installed actuators on the Normal Residual Heat Removal System (“RNS”) valves in room 11208 at elevation 94 feet on the east side of containment.
- Installed KQ10 Reactor Coolant Module in room 11104 at elevation 71 feet 6 inches inside containment.



Photo 2 – Setting of Unit 3 Steam Generator

- Installed Steam Generator B inside the containment vessel.
- Installed rebar and leak chase angles for the In-containment Refueling Water Storage Tank (“IRWST”) floor to elevation 103 feet on the west side of containment.
- Set the Accumulator Tank A and B inside the containment vessel.
- Set the KQ22 and KQ23 Chemical and Volume Control modules inside containment.
- Placed the Auxiliary Building Area 1 concrete floors to elevation 100 feet.
- Placed seven concrete slabs and one staircase to complete the Auxiliary Building walls and floors to elevation 82 feet 6 inches.
- Placed six Auxiliary Building walls to elevation 100 feet.
- Began placing the Auxiliary Building walls to elevation 107 feet 2 inches.
- Placed the CA20 concrete floors in: Room 12463 at elevation 90 feet 3 inches; Room 12563 at elevation 92 feet 8 inches; and Room 12363 at elevation 107 feet in the Auxiliary Building.
- Placed concrete in Courses 05 and 06 of the Shield Building.
- Completed concrete placements RC-02, RC-04A, RC-05B from elevation 100 feet to 117 feet 6 inches in the cylindrical wall of the Shield Building.
- Completed concrete placements RC-03A and RC-03B from elevation 100 feet to 107 feet 2 inches in the cylindrical wall of the Shield Building.



Photo 3 – Unit 3 Containment Vessel and Shield

Unit 3 Turbine Island

- Significant progress continued during the Reporting Period.
 - Installed approximately 1,199 tons of structural steel.
 - Placed approximately 1,439 cubic yards of concrete.
 - Installed approximately 5,169 linear feet of large bore pipe and pipe supports.
- Completed all six roof concrete placements at elevation 254 feet.

- Commenced interior wall panel installation in rooms 20501, 20502 and 20503 at elevation 141 feet for Initial Energization.
- Placed concrete floor slab 7 at elevation 183 feet.
- Placed concrete floor slabs 8A, 8B, 8C and 8D at elevation 196 feet.
- Placed concrete floor slabs 1 and 2 at elevation 230 feet 9 inches.



Photo 4 – Unit 3 Turbine Building Exterior

- Placed first bay concrete slabs at elevation 117 feet 6 inches.
- Continued installation of commodities (e.g. HVAC, piping, electrical).
- Continued installation of exterior wall siding.

Unit 3 Annex Building

- Significant progress continued during the Reporting Period.
 - Placed approximately 815 cubic yards of concrete.
 - Installed approximately 143 tons of rebar.
 - Installed approximately 317 tons of structural steel.
- Placed wall 09 in Area 1 and wall 3 in Area 3 to elevation 133 feet 6 inches.
- Placed wall 04, 10.1, and 14 in Area 1 and wall 10.2 in Area 2 to elevation 135 feet 3 inches.
- Placed concrete slabs in Area 1 and 2 at elevation 135 feet 3 inches.



Photo 5 – Unit 3 Annex Building

- Placed wall 10.2 in Area 2 to elevation 139 feet 3 inches.
- Placed wall 09 and wall 10.1 in Area 1 to elevation 149 feet.
- Set two 6.9kV switchgears in rooms 40413 and 40414.
- Completed installation of one hundred twenty Non-Class 1E DC and UPS System (“EDS”) batteries in room 40309.
- Placed Area 3 concrete walls 28, 29, 30, 132, and S02 to elevation 106 feet 2 inches.
- Installation of HVAC duct, cable trays and supports in addition to battery racks in the battery and battery charger rooms.

Unit 3 Cooling Tower

- Began placing concrete for the ring wall of the Cooling Tower.
- Placed concrete to elevation 222 feet for the apron walls of the Cooling Tower Pump Station.

Unit 4 Nuclear Island

- Significant progress continued during the Reporting Period.
 - Installed approximately 233 tons of rebar.
 - Placed approximately 2,368 cubic yards of concrete.
- Placed concrete to elevation 87 feet 6 inches on the west side of inside containment vessel.
- Set wall modules CB27 and CB28 for the CVS room in the north section of containment from elevation 96 feet to 105 feet 2 inches.
- Placed one concrete floor in the Auxiliary Building at elevation 74 feet 6 inches.
- Placed six concrete walls in the Auxiliary Building to elevation 82 feet 6 inches.
- Placed five concrete floors in the Auxiliary Building at elevation 82 feet 6 inches.
- Placed three concrete walls in the Auxiliary Building up to elevation 100 feet.
- Placed concrete inside the CA20 structural module walls to elevation 85 feet.
- Set pre-cast concrete floor panel for Room 12153 in the Auxiliary Building at elevation 82 feet 6 inches.
- Set mechanical modules KB11 and KB12 in the Auxiliary Building at elevation 66 feet 6 inches.
- Set effluent hold-up tanks A and B in the Auxiliary Building at elevation 66 feet 6 inches.
- Set mechanical module R104 in the Auxiliary Building at elevation 74 feet 10 inches.
- Set structural steel floor module in CA20 rooms 12162 and 12163 at elevation 82 feet 6 inches.

- Placed concrete under the Containment Vessel Bottom Head (“CVBH”) to elevation 90 feet 6 inches on the east side.
- Placed concrete under the CVBH to elevation 94 feet.
- Completed the wedge concrete placement under the CVBH to elevation 94 feet.
- Completed installation, weld out and placed concrete inside course 01, 02, and 03 of the Shield Building.
- Set the Main Steam Feedwater panel on the Shield building.

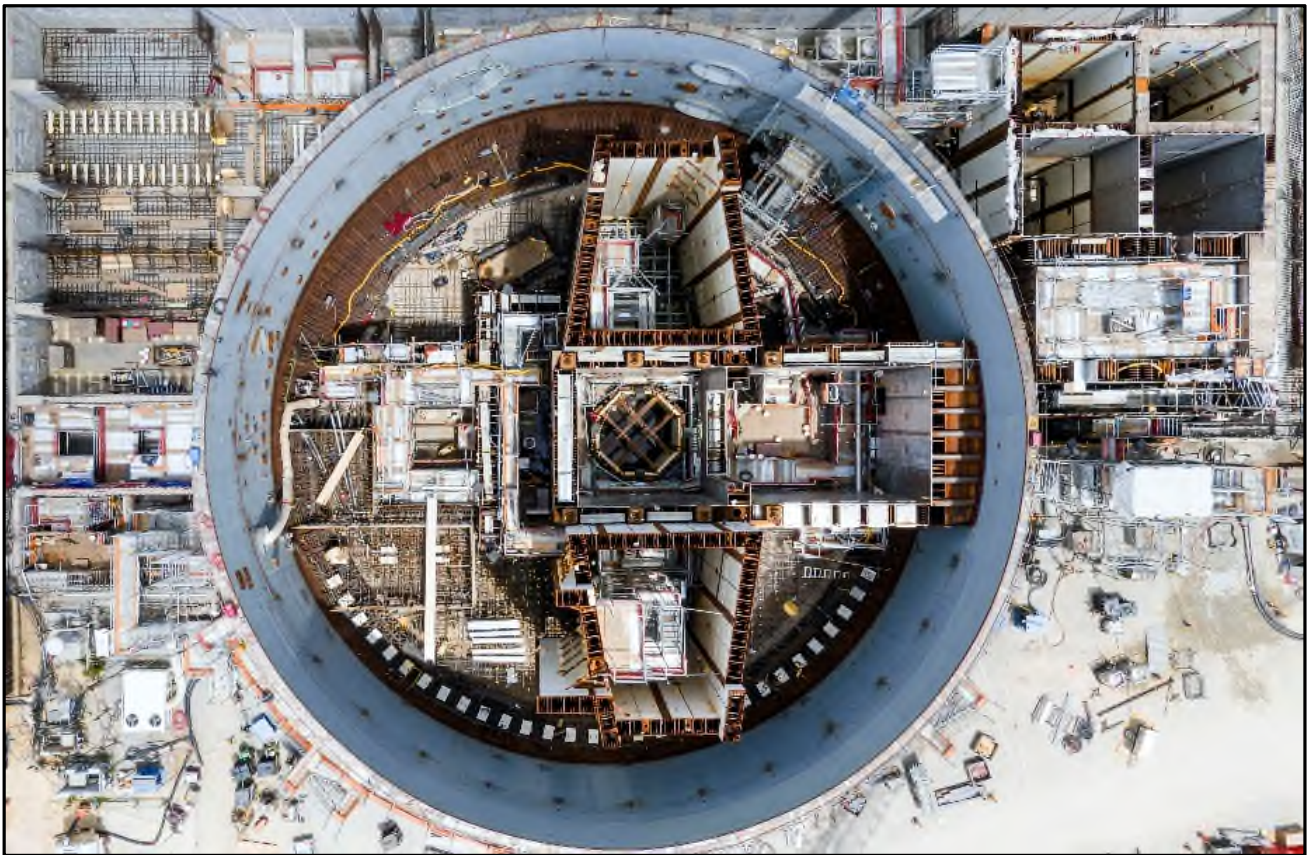


Photo 6 – Unit 4 Nuclear Island

Unit 4 Turbine Island

- Significant progress continued during the Reporting Period.
 - Placed approximately 834 cubic yards of concrete.
 - Installed approximately 219 tons of rebar.
 - Installed approximately 2,068 tons of structural steel.
- Set Feedwater heaters 7A and 7B at elevation 141 feet 3 inches.
- Set Feedwater heaters 3A, 3B, 4A, 4B, 6A and 6B at elevation 170 feet.
- Set the waste oil tank at elevation 141 feet 3 inches.
- Installed Condenser B feedwater heaters 1A and 2A at elevation 141 feet 3 inches.
- Placed concrete slabs 1, 2 and 3 at elevation 120 feet 6 inches.
- Placed concrete slabs 1, 2, and 3 at elevation 141 feet 3 inches.
- Placed concrete slab 8B at elevation 196 feet 6 inches and slab 8D at elevation 183 feet 1.5 inches.
- Commenced installation of first bay rebar walls to elevation 122 feet.



Photo 7 – Unit 4 Turbine Building Deck

Unit 4 Annex Building

- Significant progress continued during the Reporting Period.
 - Placed approximately 2,683 cubic yards of concrete.
 - Installed approximately 219 tons of rebar.
 - Installed approximately 378 tons of structural steel.



Photo 8 – Unit 4 Annex building

- Placed concrete in Area 1 and Area 2 basemat to elevation 100 feet.
- Installed structural steel to elevation 183 feet in Area 2 and to elevation 155 feet 6 inches in Area 3.
- Placed Area 3 concrete walls 01, 02, 10, 16, 19, 26, 27, 28, 29, 30, and 132 from elevation 100 feet to 107 feet 2 inches.
- Commenced installation of the Area 3 rebar mat to elevation 107 feet 2 inches.
- Flow filled rooms 40358, 40340 and staircase S03 in Area 3 from elevation 100 feet to 106 feet 2 inches.
- Placed Area 2 concrete wall 03 from elevation 100 feet to elevation 107 feet 2 inches.

Unit 4 Cooling Tower

- Continued installation of piping, fill, and the east side stair tower.

Balance of Plant

- Completed construction of the Personnel Access Point (Building 304) concrete masonry unit (“CMU”) walls and installed the Bullet Resistance Enclosure (“BRE”).
- Completed concrete placements for the Communication Support Center (Building 305) basement walls.
- Continued installation of underground piping, electrical duct banks and cables.
- Turnover of the Auxiliary Pumphouse (Building 315) building as well as the Offsite Retail Power System ZRS-01, ZRS-02, ZRS-04, and Special Process Heat Tracing System EHS-06 Boundary Identification Packages (“BIPs”) were completed during the reporting period.
- Continued concrete placements for the Unit 4 wastewater retention basin.
- Continued installation of the initial energization grounding grid.
- Continued wall concrete placements for the river water intake structure.
- Continued construction of the Unit 4 transformer walls and set Reserve Auxiliary Transformers (“RATs”) 4A and 4B.



Photo 9 – Communication Support

Transmission/Switchyard

- Energized and commissioned the Vogtle Unit 4 500kV high voltage switchyard (“HVSY”) and energized the 500kV bus tie lines No. 1 and No. 2 from Vogtle 2 HVSY to Vogtle 4 HVSY.



Photo 10 – 500 kV High Voltage Switchyard

- Relocated the West McIntosh and Warthen 500kV lines from Vogtle 2 to Vogtle 4 HVSY and energized.
- Completed all 47 miles of conductor installation and completed all spacer dampers to the Thomson Primary substation on the Thomson-Vogtle 500kV line.
- Georgia Power Line Construction completed the final two spans on the Thomson-Vogtle 500kV line into the Vogtle 1 and 2 high voltage switchyard.
- Completed and commissioned the Vogtle Switching Station (“VSS”) expansion and the new distribution breakers to the Vogtle 3 and 4 construction site.
- Georgia Power Distribution installed 2 new distribution feeders from the Vogtle switching station to the Vogtle 3 and 4 site.

Licensing

- The Company received amendments to the Combined Operating License from the Nuclear Regulatory Commission (“NRC”) during the Reporting Period that support construction activities as submitted by the following License Amendment Requests (“LAR”):
 - LAR-15-018 requested approval for the relocation of Air Cooled Chiller Pump 3, VWS-MP-03 (U3/U4 Amendments No. 64/64);
 - LAR-16-007 requested addition of Density Compensation to Reactor Trip System (“RTS”) Reactor Coolant Flow Signal (“TSR”) (U3/U4 Amendments No. 65/65);
 - LAR-16-010 requested Nuclear Instrumentation System Excore Detector Surface Material Inspection Clarification (U3/U4 Amendments No. 66/66);
 - LAR-16-017 requested changes to Tier 1 Design Reliability Assurance Program (D-RAP) (U3/U4 Amendments No. 67/67);

- LAR-16-024 requested Column Line 7.3 Wall Reinforcement Area Change (U3 Amendment No. 68);
- LAR-16-022 requested Class 1E DC and UPS System (“IDS”) Fuse Isolation Panel Additions (U3/U4 Amendments No. 69/68);
- LAR-16-021 requested revision to Licensing Basis to IBR WCAP-17179, Rev. 6 (U3/U4 Amendments No. 70/69);
- LAR-16-006 requested changes to Protection and Safety Monitoring System (“PMS”) Logic for Source Range Flux Doubling (U3/U4 Amendments No. 71/70);
- LAR-16-026 requested changes to the Passive Core Cooling System (“PXS”) Condensate (U3/U4 Amendments No. 72/71);
- LAR-13-019 requested changes to Radwaste and Annex Building layout (U3/U4 Amendments No. 73/72);
- LAR-15-016 requested approval of Emergency Plan Integration (U3/U4 Amendments No. 74/73);
- LAR-16-009 R3 requested changes to the Structural Design of Auxiliary Building Floors (U3/U4 Amendments No. 75/74);
- LAR-16-029 requested changes to the Classification of Nonsafety-Related Instrumentation (U3/U4 Amendments No. 76/75);
- LAR-16-002 requested changes to the Proposed Emergency Action Levels (U3/U4 Amendments No. 77/76);
- LAR-16-028 requested changes to Boric Acid Storage Tank Suction Point (U3/U4 Amendments No. 78/77);
- LAR-15-017 requested an Update of Common Qualified (“Common Q”) Platform Software Program Manual and Topical Report (U3/U4 Amendments No. 79/80); and
- LAR-16-016 requested changes related to Non-destructive Examination (“NDE”) for Welds of Stainless Steel Couplers to Embedment Plates (U3/U4 Amendments No. 80/79).

Inspection, Test, Analysis, and Acceptance Criteria (“ITAAC”)

- During the Reporting Period, the Company planned to submit 127 ITAAC Closure Notifications (“ICNs”) and 180 Uncompleted ITAAC Notifications (“UINs”) in 2017.
- Submitted 16 ICNs and 36 UINs during the Reporting Period.
- Cumulative ICNs to date:
 - 137 submitted and 104 verified complete by the NRC.

- The LAR to consolidate the total number of ITAACs (reduces 227 ITAAC per Unit) was submitted to the NRC and is currently under review.
- The LAR to consolidate Emergency Planning/Security ITAAC (reduces 20 ITAAC per Unit) was submitted to the NRC was approved on August 24, 2017.

E. Start-Up

Transitioning to Operations

- As the Project continues to progress toward operations, several key milestones were achieved during the Reporting Period.
 - Initial License Training Class 2 was completed with all 19 operators passing the exam.
 - Operations Training Renewal Accreditation Self Evaluation Report (“ASER”) was approved and the accreditation team visit was completed.
 - The first four BIPs for the Auxiliary Pumphouse were accepted by the Company and are now under the jurisdictional control of the Operations organization.
- The Company leveraged operational program development and established a turnover and acceptance process to systematically takeover plant ownership.
 - The Company’s Operations, Maintenance and Engineering organizations are involved in the system turnover process as an integrated turnover acceptance team.
 - Company Operational Readiness personnel took ownership of the operation and maintenance of certain systems in the Auxiliary Pumphouse Building.
- During the Reporting Period, the Company engaged with WEC’s Preoperational Test programs to leverage the testing effort and build staff knowledge, capabilities and ownership. The cross-organizational effort has the added benefit of improved oversight of WEC’s testing efforts, driving results within the testing organization and challenging construction completion efforts and schedule. Specific examples include:
 - Company operators and engineers performed the clearance and tagging activities and engaged in preoperational testing in the Auxiliary Pumphouse Building.
 - Company maintenance personnel performing component testing.
- A cross-functional team, including WEC, SCANA and Company personnel, continued to ensure configuration management of the plant and simulator, as well as efficient implementation of the Instrumentation and Controls design upgrade from Baseline 7 to Baseline 8.

Testing, Turnover, and Start-up

- The Company's Operational Readiness Initial Test Program ("ITP") organization provided oversight to the Contractor's ITP organization testing activities to improve process efficiencies, capture lessons learned, integrate Operational Readiness activities into the Project Schedule and provide recommendations to the Contractor for testing improvements.
- Operational Readiness Engineers were seconded to the Contractor to integrate into the Contractor's organization and processes to increase effectiveness of lessons learned.
 - ITP oversight surveillances were performed on the completed testing activities to identify gaps and lessons learned.
 - Lessons learned from testing and turnover processes are being incorporated into procedure and process revisions to improve efficiency for future testing.
- The ITP Administration Manual is a collection of procedures that govern how to implement testing on the project. The NRC completed an inspection of the ITP Administration Manual in the first quarter of 2017 with no findings identified.

Digital Instrumentation and Controls

- NRC conducted several Instrumentation and Controls ("I&C") system inspections during the Reporting Period; all resulting in no non-conformances or findings.
- The Baseline 8.4 core I&C software was released to the simulator located at the WEC Cranberry facility in June 2017 to prepare for integrated system testing.
- Continued level 2 factory acceptance testing of digital control systems equipment and software.
- The Unit 3 Plant Monitoring System ("PMS") was delivered during the Reporting Period.
- Completed first hardware FCN installation at the site for the Data Display and Processing System ("DDS") and In-core Instrumentation System ("IIS").
- The hardware FCN installation for the Plant Control System ("PLS") completed.
- Company I&C Technicians will be trained on hardware installation process to supplement WEC field personnel performing hardware FCN installations.
- Updated digital systems software is planned to be released in batches to support ITP activities.
 - Batch 1 will be released to support Initial Energization.
 - Batches 2 and 3 will be released to support Cold Hydro and Hot Functional Testing.

- Batch 4 will be released to support Nuclear Application Programs and Cyber Hardening of systems.

Cyber Security

- The Cyber Security Assessment Team (“CSAT”) continued oversight of the Contractors’ Critical Digital Asset (“CDA”) identification and assessment efforts.
- CSAT completed a review of the Contractor’s initial CDA identification report with 47,000 digital assets reviewed and comments provided to the Contractor.
- The Company implemented the internal Control of Portable Media and Mobile Devices (“PMMD”) Program.
- The Company reviewed 8 of 9 initial assessments of the Core Systems.
- The Company developed and executed a pilot Methodology and Assessment Process in collaboration with SCANA cyber security team.

Programs, Processes, and Procedures

- The Company developed an integrated Operational Readiness schedule that contains activities representing training, program development, ITAAC development and completion, and procedure development.
 - 63 of 96 programs have been approved by the Plant Review Board (“PRB”).
 - Completed approximately 50% of Maintenance Rule & Functional Equipment Group (“FEG”) activities.
 - Initial NRC inspections of Special Nuclear Material MC&A (“Material Control and Accounting”), Reactor Vessel Material Surveillance (“RVMS”), and Equipment Qualification (“EQ”) Programs were completed with no findings.
 - Completed approximately 645 procedures to support the transition to operations.
 - The Chemistry, Engineering and Maintenance training programs are in progress and continue to support operational readiness activities.

Integrate the Four Unit Site

- The common fleet emergency plan with a Vogtle 3 and 4 annex was approved by the NRC and will be implemented at Vogtle 3 and 4 in the fourth quarter of 2017.
- Operational Support Center (“OSC”) outfitting continued during the reporting period.

- Construction continued progress on the site common Communications Support Center (“CSC”) which includes the Technical Support Center (“TSC”) and Central Alarm Station.
- The site Personnel Access Point (“PAP”) construction continued during the reporting period.
- LAR 16-002 to update the Emergency Preparedness Emergency Action Levels (“EALs”) for Vogtle 3 and 4 has been approved by the NRC.
- Onboarded and commenced training 19 new Vogtle 3 and 4 security officers to support construction-related activities within the Vogtle 1-4 footprint.

13. Omitted per 9th/10th VCM Order.

14. An updated comparison of the economics of the certified project to other capacity options.

See Section VI. Economic Analysis.

15. The Company will be under a continuing obligation to supplement its response to PIA Staff DR STF-TN-1-2 by ensuring that the financing data reflected in the schedules attached to that DR response reflect the most current and updated information at the time of each semi-annual monitoring report. In addition, the Company will provide the most current information shared with each of the Rating Agencies.

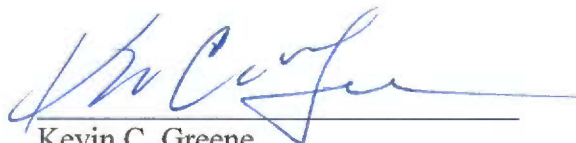
Simultaneous with this filing, the Company has filed supplemental PIA Staff DR STF-TN-1-2, and has included in that filing the most current information shared with each of the Rating Agencies.

IX. CONCLUSION

For the foregoing reasons, the Company requests that the Commission enter an order at the conclusion of these proceedings and in that order make the following findings:

1. That pursuant to O.C.G.A. § 46-3A-7(b), the Commission approves the new cost and schedule forecast and finds that it is a reasonable basis for going forward; and that if the Commission disapproves all or part of the proposed cost and schedule revisions, the Company may cancel Units 3 and 4 and recover its actual investment in the partially completed Facility pursuant to O.C.G.A. § 46-3A-7(d).
2. That the Stipulation remains in full force and effect, including the Company retaining the burden of proving all capital costs above \$5.68 billion were prudent.
3. That while this Commission will make no prudence finding in the upcoming VCM 17 proceeding, nor will the certified amount be amended consistent with the Stipulation, the Commission recognizes that the certified amount is not a cap, and all costs that are approved and presumed or shown to be prudently incurred will be recoverable by Georgia Power.
4. That the Company is not a guarantor of the Toshiba Parent Guaranty, and the failure of Toshiba to pay the Toshiba Parent Guaranty, the failure of Congress to extend the PTCs, or the failure of the DOE to extend the DOE Loan Guarantees to reflect the increased capital amounts, will not reduce the amount of investment the Company is otherwise allowed to collect.
5. That as conditions change and assumptions are either proven or disproven, the Owners and the Commission may reconsider the decision to go forward.

Respectfully submitted, this 31st day of August, 2017.

A handwritten signature in blue ink, appearing to read 'K. C. Greene', is written over a horizontal line.

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