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September 6, 2019

Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, Alabama 36104

Attention: Mr. Walter L. Thomas, Jr.
Secretary

Re: Petition for a Certificate of Convenience and Necessity
Docket No. __________

Dear Secretary Thomas,

On behalf of Alabama Power Company, we are submitting for filing the enclosed petition for a certificate of convenience and necessity, along with supporting testimony and exhibits. As the supporting materials include information that is confidential and proprietary to the Company and to third parties, we are providing a version for public posting along with a non-public confidential version to be retained under seal by the Commission. Also enclosed is a Confidentiality Agreement for interested parties that are permitted to intervene in the proceeding and who desire access to the non-public confidential materials under the terms and conditions set forth in said agreement. Lastly, the Company is providing a proposed form of notice.

If you have questions concerning any aspect of the Company's filing, please contact the undersigned.

Very truly yours,

Dan H. McCrary

Dan H. McCrary

DHM:eb

Encl.

ALABAMA POWER COMPANY,

Petitioner

PETITION: For a certificate of convenience and necessity for: (i) the construction and installation of combined cycle generating capacity at the site of Petitioner's Barry Steam Plant located in Mobile County, Alabama; (ii) the acquisition of existing combined cycle generating capacity in Autauga County, Alabama; (iii) the acquisition of rights and the assumption of payment obligations under a power purchase agreement for the output of combined cycle generating capacity operated in Mobile County, Alabama; and (iv) the acquisition of rights and the assumption of payment obligations under power purchase agreements for the output from five solar photovoltaic and battery energy storage systems, located in Calhoun, Chambers, Dallas, Houston and Talladega Counties; together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident thereto.

Docket No. __________

TO THE ALABAMA PUBLIC SERVICE COMMISSION:

Alabama Power Company ("Petitioner" or "Company") hereby requests, pursuant to Alabama Code § 37-4-28 and Parts A and B of Rate CNP–Adjustment for Commercial Operation of Certificated New Plant, that the Commission issue an order in this proceeding granting a certificate of convenience and necessity ("Certificate"). By the Certificate, as described in this Petition and in the testimony and exhibits filed in support thereof, the Commission would authorize the Company to: (i) construct and install combined cycle generating capacity at the site of the Petitioner's Barry Steam Plant located in Mobile County, Alabama; (ii) acquire the Central Alabama Generating Station, a combined cycle generating facility located in Autauga County, Alabama; (iii) acquire rights and assume payment obligations under a power purchase agreement ("PPA") pertaining to the Hog Bayou Energy Center, a combined cycle generating facility located in Mobile County, Alabama; and (iv) acquire rights and assume payment obligations under five PPAs pertaining to solar photovoltaic facilities, each being paired with a battery energy storage system ("BESS"), as located in Calhoun, Chambers, Dallas, Houston and Talladega Counties. In addition to the requested authority under the Certificate, the Company is seeking authorization to pursue approximately 200 MW of demand-side management and distributed energy resource programs.

In support of its Petition, the Company states as follows:

1. Petitioner is a corporation organized and existing under the laws of the State of Alabama that owns and operates electric generating plants and has other sources of supply of electric power, all of which are connected by or delivered to transmission lines and facilities forming the Company's interconnected electrical system. Petitioner is engaged as a public utility in the distribution and sale to the public of the electricity so produced and acquired by it, and such utility service is furnished by Petitioner to the public in a large section of the State.

2. In order to meet the demand for electricity in the territory served by the Company and to render adequate and reliable service to the public, as contemplated under Title 37 of the Code of Alabama, it is necessary and appropriate for the Company to make the following additions to its portfolio of supply resources.[1]

[1] The Company's reliability-based need for additional resources is addressed in the supporting testimony and exhibits of John B. Kelley and Jeffrey B. Weathers.

3. Petitioner proposes to construct and install combined cycle generating capacity at the site of Petitioner's Barry Steam Plant located in Mobile County, Alabama ("Barry Unit 8").[2] Barry Unit 8 will initially provide approximately 726 MW of winter-rated capacity (increasing to approximately 743 MW of winter-rated capacity under a subsequent uprate), with an expected useful life of 40 years. Commercial operation is expected in November, 2023. The principal components of Barry Unit 8 include one Mitsubishi 501 J-series air-cooled combustion turbine, one heat recovery steam generator with duct firing, and one condensing reheat steam turbine (together comprising a 1-on-1 combined cycle configuration), along with other balance of plant equipment, including a cooling tower for closed-cycle cooling operations. The unit will be constructed under a turnkey Agreement for Engineering, Procurement and Construction with Mitsubishi Hitachi Power Systems Americas, Inc. and Black & Veatch Construction, Inc. The project will take maximum advantage of existing infrastructure at the Plant Barry site, but some infrastructure additions will be required, such as a new tie line to the existing adjacent Ellicott 230 kV substation, a gas extension line from the existing Plant Barry gas yard to the location of the new unit, and new water lines and access roads.

4. Petitioner proposes to acquire the Central Alabama Generating Station ("Central Alabama") located in Autauga County, Alabama.[3] Central Alabama is a combined cycle facility constructed in 2003, with an estimated remaining life (post-closing) of approximately 23 years. The facility, which has a winter capacity rating of 915 MW and a summer capacity rating of 890 MW, is owned by Tenaska Alabama II Partners, L.P. (the "Partnership"), a Delaware limited partnership in which a Tenaska subsidiary is the managing general partner and majority owner.

[2] Barry Unit 8 is addressed in the supporting testimony and exhibits of Michael A. Bush.

[3] The acquisition of Central Alabama, as well as the associated PPA that expires in mid-2023, is addressed in the supporting testimony and exhibits of John B. Kelley.

Upon the closing of a Purchase and Sale Agreement, the Company will hold a 100 percent interest in the Partnership, after which all rights, title and interest of the Partnership in its assets (Central Alabama, along with related assets and properties) will be transferred into Petitioner. Until May 2023, Central Alabama is subject to a PPA with a third party under which the third party is entitled to the capacity of the facility and the associated energy. The third-party PPA will remain in place until it expires, with the Company entitled to receive the associated revenues. Petitioner will thereafter have the same rights and responsibilities associated with Central Alabama as with any other generating facility that it owns.

5. Petitioner proposes to acquire rights and assume payment obligations under a PPA with Mobile Energy, LLC whereby the Company will be entitled to the entire capability of the Hog Bayou Energy Center located in Mobile County, Alabama, for a total term of approximately 19 years.[4] The Hog Bayou Energy Center is a combined cycle, natural-gas fired facility with a summer rating of 222 MW and a winter rating of 238 MW. In order to address certain near-term reliability needs of the Company, the PPA calls for an early start period beginning in 2020 through November 2023, followed by a 15-year term beginning in December 2023. Along with monthly capacity payments, the Company is responsible for an energy payment that includes a charge for each unit start, plus a charge for variable O&M expenses and a fuel adjustment based on a guaranteed heat rate. As this is a "tolling" PPA, the Company is separately responsible for the fuel-related arrangements (commodity and transportation).

6. Petitioner proposes to acquire rights and assume payment obligations under 28-year PPAs with five separate projects to be located in Calhoun, Chambers, Dallas, Houston and

[4] The PPA associated with the Hog Bayou Energy Center is addressed in the supporting testimony and exhibits of John B. Kelley.

Talladega Counties.[5] Each project comprises a nominal 80 MW solar photovoltaic facility and a nominal 80 MW BESS that, given operational parameters, yield a cumulative winter capacity equivalence of 340 MW (68 MW per project). Although the payment structure for each of these five PPAs bundles both solar- and BESS-related costs into a single combined energy payment, a portion of that combined energy payment is attributable to the cost of the BESS component that provides capacity to the Company.

7. Along with the above-described supply resources, Petitioner is requesting authorization to pursue 200 MW in additional demand-side management and distributed energy resource programs.[6] Petitioner contemplates submitting them to the Commission on a program-by-program basis, with approval contingent on a reasonable demonstration that the project results in positive benefit for all customers over its term. This demonstration would take into account the costs and revenue impacts of the project and the expected value corresponding to an avoided generic capacity addition, along with other positive benefits that may accrue through load growth, load retention or other relevant considerations associated with the particular project.

8. Petitioner states that the described generating units and PPAs, together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident thereto, are

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[5] These solar/BESS projects and the associated PPAs are addressed in the supporting testimony and exhibits of John B. Kelley.

[6] These additional demand-side management and distributed energy resource programs are addressed in the supporting testimony of John B. Kelley.

necessary, advantageous, efficient and appropriate for the purposes aforesaid and are in the public interest.[7]

9. Petitioner states that the costs associated with the portfolio of resources described in this Petition will be recovered through cost recovery mechanisms established by the Commission (specifically, Rate CNP–Adjustment for Commercial Operation of Certificated New Plant, Rate ECR–Energy Cost Recovery Rate, and Rate RSE–Rate Stabilization and Equalization Factor), together with such accounting authorizations, directions and clarifications from the Commission as needed in the circumstances.[8]

WHEREFORE, Petitioner requests that this Commission, after a public hearing of all parties interested at a time and place fixed by the Commission, grant to the Company a certificate of convenience and necessity pursuant to the provisions of Alabama Code § 37-4-28 (1975) and Parts A and B of Rate CNP–Adjustment for Commercial Operation of Certificated New Plant, approving and authorizing the portfolio of resources set forth in this Petition, together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident, and that the Commission make and enter such further orders as may be necessary or appropriate.

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[7] The cost-effectiveness of the proposed portfolio of generating resources and the manner by which that determination was made are addressed in the supporting testimony and exhibits of John B. Kelley and M. Brandon Looney.

[8] The timing and manner by which costs associated with the proposed generating resources would be recovered, along with associated accounting authorizations, are explained in detail in the supporting testimony of Christine M. Baker. The regulatory process associated with the demand-side management and distributed energy resource programs is addressed in the testimony of John B. Kelley.

This 6th day of September, 2019.

ALABAMA POWER COMPANY

By: ______________________________

Executive Vice President

BALCH & BINGHAM LLP
Dan H. McCrary
Scott B. Grover
1710 North Sixth Avenue
Birmingham, AL 35203
(205) 251-8100

Attorneys for Petitioner

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

Alabama Power Company

PETITION: For a certificate of convenience and necessity for: (i) the construction and installation of combined cycle generating capacity at the site of Petitioner's Barry Steam Plant located in Mobile County, Alabama; (ii) the acquisition of existing combined cycle generating capacity in Autauga County, Alabama; (iii) the acquisition of rights and the assumption of payment obligations under a purchased power agreement for the output of combined cycle generating capacity operated in Mobile County, Alabama; and (iv) the acquisition of rights and the assumption of payment obligations under purchased power agreements for the output from five solar photovoltaic and battery energy storage systems, located in Calhoun, Chambers, Dallas, Houston and Talladega Counties; together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident thereto.

Docket No. ___________

Direct Testimony of Alabama Power Company
(Public Version)

VOLUME I

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. ________**

DIRECT TESTIMONY OF JOHN B. KELLEY
ON BEHALF OF ALABAMA POWER COMPANY

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John B. Kelley and my business address is 600 North 18th Street, Birmingham, Alabama.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Alabama Power Company ("Alabama Power" or "Company") as Director of Forecasting and Resource Planning.

Q. DESCRIBE THE PRINCIPAL BUSINESS ACTIVITY OF ALABAMA POWER.

A. Alabama Power is a public utility company, organized and existing under the laws of the State of Alabama. Alabama Power operates an integrated electric utility system across a large portion of the State. To this end, the Company's primary business activities are the generation, transmission and distribution of electricity to the public.

Q. BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Illinois in 1983 with a Bachelor of Science in Electrical Engineering degree. In 1987, I received a Master of Business Administration degree from the University of Alabama at Birmingham. I began my career with Southern Company in 1983 as an engineer in the transmission planning department of Southern

Company Services, Inc. ("SCS"). My responsibilities increased in the generation planning and integrated resource planning departments, including a two-year consulting project for the former Southern Electric International. In 1990, I began working for Alabama Power in the marketing department, where I maintained supervisory responsibilities over project analysis. I later served as the Manager of Marketing Services within the Alabama Power retail marketing organization, with responsibilities that included the development of retail market plans, economic evaluations, and mass marketing programs. I was named Director of Forecasting and Resource Planning in 2008.

Q. WHAT ARE YOUR JOB DUTIES AND RESPONSIBILITIES?

A. As Director of Forecasting and Resource Planning, I am responsible for the Company's Integrated Resource Plan ("IRP"), which includes the identification of timely and cost-effective expansions of Alabama Power's resources, such as generation additions, long-term power purchases, demand-side options, and renewable energy and environmentally-specialized generating resources. In addition, I have responsibility for the development of Alabama Power's demand, energy, customer and revenue forecasts.

Q. ARE YOU FAMILIAR WITH THE COMPANY'S PLANS FOR THE RESOURCE ADDITIONS DESCRIBED IN THE PETITION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY?

A. Yes.

Q. HAVE YOU READ THE PETITION FILED BY THE COMPANY IN THIS PROCEEDING?

A. Yes.

Q. ARE THE STATEMENTS CONTAINED IN THE PETITION TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE, INFORMATION AND BELIEF?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is basically three-fold, and is organized accordingly. First, I will discuss the IRP process used by the Company to determine the need for new capacity resources in order to continue to provide reliable service to customers. I will then overview how Alabama Power identified potential resource opportunities for evaluation, including the Request for Proposals ("RFP") process that was used to determine the availability of reliable and cost-effective capacity alternatives from the wholesale market. Finally, I will summarize the proposed resource additions that the Company has selected for certification as providing reliable service at the lowest practicable total cost (capacity and energy) over the long run. I also will discuss the Company's request for authorization to pursue 200 megawatts ("MW") of demand-side management and distributed energy resource programs.

Q. ARE OTHER WITNESSES ALSO TESTIFYING IN SUPPORT OF THE COMPANY'S PETITION?

A. Yes. In addition to my testimony, the Company is offering the testimony of Jeffrey B. Weathers, Michael A. Bush, M. Brandon Looney and Christine M. Baker.

Q, BRIEFLY DESCRIBE THE TOPICS ADDRESSED BY THOSE OTHER WITNESSES.

A. Mr. Weathers will discuss the latest reserve margin study, which confirms the significant shift in reliability risk from the summer season to the winter season and the associated use of seasonal planning by the Company. Mr. Weathers also discusses the adoption of a winter target reserve margin in addition to the summer target reserve margin.

Mr. Bush describes the development of the Company's turnkey option at the Plant Barry site, which will be accomplished through an agreement between the Company and Mitsubishi Hitachi Power Systems Americas, Inc. and Black & Veatch Construction, Inc. for the associated engineering, procurement and construction.

Mr. Looney overviews the processes used to evaluate the various options available to meet the Company's reliability needs and determine which ones would comprise the most cost-effective portfolio of resource additions.

Finally, Ms. Baker will address how various rate mechanisms and accounting authorizations will apply to the components of the proposed resource portfolio.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE COMPANY AND THE OTHER OPERATING COMPANIES OF THE SOUTHERN ELECTRIC SYSTEM WITH REGARD TO GENERATION PLANNING AND SYSTEM OPERATION?

A. The Company and the other operating companies of the Southern electric system operate their systems on a coordinated basis in order to achieve economies of scale and other available efficiencies. The Intercompany Interchange Contract ("IIC"), which is a rate schedule filed with and approved by the Federal Energy Regulatory Commission, governs the treatment of and accounting for: (i) temporary surpluses and deficits of capacity among the companies; and (ii) energy exchanges and corresponding settlements associated with the economic dispatch of the system power pool. Operating in this manner under the IIC lowers total production cost and enhances system reliability, which benefits all of the operating companies. In addition, the long-term load forecasts of the individual operating companies are combined into a single integrated forecast, which enables them to benefit from system diversity through reserve margins that are lower than would be required were each to operate on a stand-alone basis.

For the affiliated retail operating companies, the resource additions necessary to provide reliable and economic service are determined through a comprehensive and coordinated resource planning process. Using long-term planning reserve margin guidelines, the process determines the amount of capacity, and indicates the type of resource additions, required to provide reliable, efficient and economical service. It should be emphasized that, although engaging in coordinated planning and operation, each retail operating company retains the right and bears the responsibility to determine the resource additions appropriate for its service territory and to operate its system so as to satisfy the needs of its customers in a reliable and efficient manner. The expectation that each operating company will have resources to reliably serve its own customers, which I understand to be an integral part of Alabama Power's status as a public utility under Alabama law, is likewise a fundamental premise embodied the IIC.

I. IRP Process and Indicated Resource Need

Q. WHAT IS THE PURPOSE OF THE IRP PROCESS AND HOW IT IS USED BY THE COMPANY?

A. The IRP process is an analytical tool designed to identify the timing, amount, and types of resources necessary to serve the long-term expected energy and demand requirements of Alabama Power's customers. It involves choosing from a broad range of resource options to produce an indicative benchmark plan of resource additions that is reasonably expected to meet anticipated load obligations (including an appropriate reserve margin) at the lowest practicable cost over the long run. These results help guide the Company as it undertakes to develop and implement a supply-side and demand-side resource strategy that will enable it to continue to provide service that is reliable and cost effective for customers.

Q. CAN THE IRP PROCESS BE REDUCED TO WRITING?

A. Integrated resource planning is not a document, but rather a comprehensive, data-intensive process. The Company does, however, develop a summary report that provides considerable detail regarding the objectives of the IRP process, the major steps, tools, and inputs it employs, and other considerations that together produce the indicative benchmark plan of future resource additions. A copy of the public version of the 2019 IRP Summary Report is appended to my testimony as Exhibit JBK-1.

Q. WAS THIS EXHIBIT PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. The Forecasting and Resource Planning organization that I oversee is responsible for implementing the Company's IRP process, including the preparation of this 2019 IRP Summary Report.

Q. BRIEFLY OVERVIEW THE COMPANY'S IRP PROCESS.

A. As described more fully in the 2019 IRP Summary Report, the IRP is an iterative process that evaluates existing and potential resource options to identify the best combination of needed additions, in terms of reliability and expected total cost for serving customers. Using updated marginal cost projections to capture significant changes related to fuel, technology, regulatory compliance and other such factors, the Company evaluates its existing supply-side options to determine what, if any, resource additions or modifications are economically viable. Similarly, the Company uses the same marginal cost approach to evaluate demand-side management ("DSM") programs to determine those that appear cost-effective and thus eligible for inclusion in a new benchmark plan. These results, along with comparable analyses applied to new candidate technologies, are integrated to produce an optimum combination of demand-side and supply-side resources that comprise the benchmark plan. This benchmark plan shows additions that, together with the Company's existing portfolio of resources, will meet the projected demand and energy needs of the Company's customers in a reliable and cost-effective manner.

Q. HOW IS THE AMOUNT AND TIMING OF THE RESOURCE NEED DETERMINED?

A. The determination of the amount and timing of the needed resources starts with an update to the Company's forecast of future energy and peak demand requirements for the next 20 years. Based on this updated load forecast, the Company identifies a schedule of resources required to serve that load reliably, which necessarily includes an appropriate reserve margin.

Q. WHAT IS THE PURPOSE OF A RESERVE MARGIN?

A. Electric utility customers expect and depend on a high level of service reliability. Accordingly, a retail electric utility like Alabama Power must have an economically balanced margin of generating capacity above its anticipated peak load, i.e., a reserve margin. This enables the Company to maintain sustained reliability for its customers, notwithstanding unpredictable events such as equipment failures or extreme weather.

Q. HOW WERE THE RESERVE MARGINS USED IN THE COMPANY'S 2019 IRP DETERMINED?

A. The reserve margins used by the Company are based on the 2018 Reserve Margin Study that analyzed the reliability challenges on the system and then identified risk-adjusted reserve margins that would minimize the combined costs of maintaining reserve capacity, system production costs, and customer costs associated with service interruptions. The 2018 Reserve Margin Study is addressed in the testimony of Mr. Weathers, including a discussion of the underlying methodology and the increased reliability risk in the winter. Winter-related reliability issues are also addressed in the 2019 IRP Summary Report.

The confirmation in the 2018 Reserve Margin Study of a significant increase in winter reliability risks (as identified in the preceding 2015 Reserve Margin Study) led the Company (along with the other operating companies) to begin using seasonal planning in the IRP process. This means that, while in the past the Company has historically relied upon a target reserve margin only for the summer season, it is now using independent evaluations of resource adequacy in both the summer and the winter peak periods to ensure that system reliability is fully addressed year round. This results in the establishment of separate target reserve margins for each of those seasons.

Q. HAS THE COMPANY SEEN CHANGES IN THE LOADS OF ITS CUSTOMERS THAT FURTHER VALIDATE THE ADOPTION OF SEASONAL PLANNING?

A. Yes. Alabama Power has traditionally been considered summer peaking, meaning its annual peak demand has occurred during the summer months. However, in recent years, Alabama Power's winter peak demand has exceeded the summer peak demand. The 2014 actual winter peak was 12,610 MW, which exceeded the prior all-time peak of

12,496 MW that occurred in the summer of 2007. Moreover, on a weather-normalized basis, the Company's winter peak has exceeded its summer peak since 2010, and the Company's most recent load forecast continues to project a winter peak demand that is higher than the summer peak demand.

Q. DO THE RESERVE MARGINS THAT UNDERLIE THE 2019 IRP REFLECT THESE SEASONAL REALITIES?

A. Yes. The Company is maintaining the current 16.25 percent long-term system target reserve margin for the summer peak planning season. To address the winter reliability concerns, the Company is adding a long-term winter target reserve margin of 26 percent for the system, to be used in planning for the winter peak season.

Q. DOES THIS MEAN THAT THE COMPANY MUST HAVE RESERVE MARGINS AT BOTH OF THOSE LEVELS TO MAINTAIN RELIABIITY IN THE RESPECTIVE SEASONS?

A. No. As previously explained, Alabama Power and the other operating companies of the Southern electric system operate on a coordinated basis in order to achieve economies of scale and other available efficiencies. One of the recognized advantages of operating in this manner is the benefit of system diversity, enabling the individual companies to maintain lower "diversified" reserve margins while collectively achieving the higher target reserve margin for the system. Thus, for purposes of long-term planning, Alabama Power's diversified summer target reserve margin is 14.89 percent and its diversified winter target reserve margin is 25.25 percent.

Q. HAS THE ALABAMA PUBLIC SERVICE COMMISSION ("COMMISSION") HAD OCCASION TO REVIEW AND ADDRESS THE IRP PROCESS USED BY THE COMPANY?

A. Yes. The Company has used integrated resource planning for many years and the resulting IRPs have prompted a number of petitions for certification of new resources to satisfy a reliability-based need for additional capacity. On several of those occasions, the Commission has specifically endorsed that process.

Q. DID THE COMPANY FOLLOW THAT SAME PROCESS TO DETERMINE THE RESOURCE NEEDS REFLECTED IN THE CURRENT PETITION?

A. Yes. As one would expect, inputs to the IRP (such as marginal cost projections, load forecasts, target reserve margins, and candidate technologies) are revised and updated over time, but from a conceptual and methodological standpoint, the Company continues to apply the same fundamental IRP process previously endorsed by the Commission. To keep the Commission apprised of the ongoing status of the IRP process, the Company provides to Commission staff its periodic IRP results (typically performed at three-year intervals) and meets with staff to review and discuss the results, including changes in the underlying drivers.

Q. WHAT ARE THE CAPACITY NEEDS INDICATED BY THE IRP FOR THE RESPECTIVE SEASONS?

A. Over the next ten years, the 2019 IRP shows the Company is within its diversified target for the summer season. In the winter, however, the Company's ("APC") reserve margins are below the applicable target, [redacted].

Capacity Need (MW) - Winter		
Year	APC Reserve Margin (%)	APC Need (MW)
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]

These results demonstrate that, [redacted], Alabama Power has a reliability-driven need for additional resources in the winter.

Q. WHAT CAUSES THE INDICATED AMOUNT OF NEED TO SOMETIMES MOVE DOWN FROM ONE YEAR TO THE NEXT?

A. Typically, the amount of need will move up gradually in response to normal load growth. In some years, however, there can be a larger shift, either in the Company's projected load (due, for example, to a new or expiring contract) or in its available resources (due, for example, to a unit addition, expiration of a power purchase agreement, or unit unavailability assumptions).

Q. DO THE SYSTEM RESERVE MARGINS, WHICH REFLECT ALABAMA POWER'S OBLIGATIONS AND RESOURCES ALONG WITH THOSE OF THE OTHER RETAIL OPERATING COMPANIES, INDICATE SUCH A CAPACITY SHORTFALL IN THE WINTER OVER THIS SAME PERIOD?

A. No. When viewed on a coordinated system basis, the reserve margins and indicated capacity additions needed to satisfy the long-term winter planning reserve margin over the 2020-2028 timeframe are as follows.[1]

2019 IRP Winter Benchmark Base Case with Generic Additions						
Year	APC CT's	APC CC's	APC RM	APC NEEDS (MW)	ROC RM	ROC NEEDS (MW)
2020	-	-	[redacted]	[redacted]	[redacted]	[redacted]
2021	-	-	[redacted]	[redacted]	[redacted]	[redacted]
2022	-	-	[redacted]	[redacted]	[redacted]	[redacted]
2023	300	-	[redacted]	[redacted]	[redacted]	[redacted]
2024	-	-	[redacted]	[redacted]	[redacted]	[redacted]
2025	-	900	[redacted]	[redacted]	[redacted]	[redacted]
2026	-	-	[redacted]	[redacted]	[redacted]	[redacted]
2027	600	-	[redacted]	[redacted]	[redacted]	[redacted]
2028	300	270	[redacted]	[redacted]	[redacted]	[redacted]

Q. WHY DOES ALABAMA POWER HAVE LARGE WINTER CAPACITY NEEDS OVER THIS TIMEFRAME, WHEREAS THE COLLECTIVE SOUTHERN SYSTEM DOES NOT?

A. These capacity needs arise for Alabama Power because its load peaks in the winter season. In contrast, the largest of the retail operating companies, Georgia Power, continues to experience its peak load in the summer. The fact that Georgia Power does so, coupled with its size relative to the other companies, is the reason the winter need shown for the collective system is considerably less, as Georgia Power currently has capacity on its system that can be used to help support the winter requirements of Alabama Power's customers.

[1] For purposes of this table, "CT" means combustion turbine, "CC" means combined cycle, "ROC" means retail operating companies, and "RM" means reserve margin.

Q. GIVEN THE COORDINATED OPERATIONS OF THE SOUTHERN SYSTEM, WHY DOESN'T ALABAMA POWER RELY ON CAPACITY OF THE OTHER OPERATING COMPANIES FOR WINTER RELIABILITY?

A. As noted earlier, each retail operating company is responsible for determining the resource additions appropriate for its own service territory that will enable it to meet the needs of its customers in a reliable and cost-effective manner. Interactions with the affiliated companies through mechanisms such as coordinated planning and operation can and do provide benefits and cost savings (including the ability to take advantage of temporary surplus capacity on the system), but they do not alter this fundamental duty and responsibility. Moreover, much of the capacity that gives rise to the higher reserve levels at the other retail affiliates comprises older fossil steam resources. It is no surprise that such resources across the country are under significant cost pressure that threatens their continued operation, for reasons including the ongoing cost of environmental compliance, forecasted low gas prices, and modest load growth. To that end, Georgia Power recently proposed the retirement of Plant Hammond Units 1-4 and Plant McIntosh Unit 1 (totaling approximately 980 MW), and specifically noted economic challenges associated with the continued operation of Plant Bowen Units 1-2 (totaling approximately 1500 MW). Under the Order Adopting Stipulation As Amended issued by the Georgia Public Service Commission dated July 29, 2019, the Hammond and McIntosh units were officially retired and capital spending limits were established for Bowen Units 1-2 for the next three years. [redacted]

I would emphasize that Alabama Power is not suggesting, and does not know, what Georgia Power's ultimate plans may be for the Bowen units. My point is that these are Georgia Power resources and as the owner it controls decisions impacting their future operation (subject, of course, to requisite regulatory approvals under state law). The same would be true for Mississippi Power Company and the resources that it owns. Alternatively, these companies could seek to make wholesale sales predicated on their owned capacity. In either case, the effect would be a reduction in the level of available capacity reserves on the system. Accordingly, Alabama Power cannot and should not count on the sustained availability of capacity owned by its retail affiliates for use in serving the requirements of Alabama customers, particularly given the Company's reliability obligations as a regulated public utility under Alabama law.

Q. GIVEN THE RESULTS OF ALABAMA POWER'S IRP PROCESS AND OTHER RELEVANT CONSIDERATIONS, HOW MUCH CAPACITY DOES THE COMPANY NEED TO SECURE FOR LONG-TERM RELIABILITY PURPOSES?

A. The IRP results shown for Alabama Power and for the system, coupled with other factors impacting reliable long-term supply, demonstrate a need for the Company to add approximately 2400 MW of additional resources by the 2023-2024 timeframe. This advancement of the resource additions otherwise indicated by the coordinated system plan across the 2023-2028 timeframe will mitigate the described risks and satisfy the Company's statutory duty to make reasonable enlargements of its system to meet the demand of those customers for whom it holds a duty to serve. The portfolio of resource additions proposed for certification, as described in more detail in the last part of my testimony, represent a reliable and cost-effective means of satisfying that need.

II. <u>Identification of Potential Resource Opportunities</u>

Q. HOW DID ALABAMA POWER GO ABOUT IDENTIFYING RESOURCE OPTIONS AND OPPORTUNITIES THAT MIGHT PROVE TO BE COST-EFFECTIVE MEANS OF MEETING ITS RELIABITY NEED?

A. The Company's overarching goal in this undertaking was to consider any resource opportunities that could be appropriate to meet this capacity need, and to then subject those potential options to a rigorous and consistent evaluation. The array of options included the turnkey delivery of a new facility, numerous capacity offerings from the wholesale market, and certain other proposals that evolved from a prior solicitation of renewable energy projects.

Q. DESCRIBE THE DEVELOPMENT OF THE TURNKEY PROJECT.

A. Building and owning needed capacity resources is a traditional option that is almost always available to a public utility. In this instance, that option took the form of a turnkey combined cycle project at Plant Barry, which is described more fully in Mr. Bush's testimony.

Q. HOW DID ALABAMA POWER OBTAIN LONG-TERM CAPACITY OFFERINGS FROM THE WHOLESALE MARKETS?

A. In order to determine the terms and conditions of available opportunities in the wholesale market, the Company publicized and issued a capacity Request for Proposals ("Capacity RFP"). A copy of that RFP is appended to my testimony as Exhibit JBK-2.

Q. WAS THE CAPACITY RFP CONDUCTED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. HAS ALABAMA POWER RECENTLY CONDUCTED ANOTHER SOLICITATION THAT FOLLOWED A SIMILAR STRUCTURE?

A. Yes. In accordance with the requirements of the Commission's order in Docket No. 32383, a Renewable RFP was conducted by Forecasting and Resource Planning in 2018 to help identify potentially viable renewable resources that might be candidates for certification pursuant to that order.

Q. BRIEFLY DESCRIBE THE CAPACITY RFP.

A. On September 21, 2018, the Company issued the Capacity RFP, soliciting proposals for capacity resources either in the form of a power purchase agreement ("PPA") or an agreement for the acquisition of new-build or existing facilities. The Company expressed a willingness to consider any type of resource that would provide reliable, dispatchable, cost-effective capacity and energy to meet the needs of its customers. Commencement of service would be in the 2019-2023 timeframe, with the amount depending upon the cost competitiveness of the respective offers as well as other options available to the Company. Notice of the RFP was publicized through BusinessWire, a press release distribution service that reaches online, print, broadcast and radio media outlets, reporters and wire services. In addition, a dedicated website was established for the Capacity RFP.

Q. WHAT WAS THE LEVEL OF RESPONSE FROM WHOLESALE MARKET PARTICIPANTS?

A. Interested bidders submitted 19 proposals that totaled approximately 5,000 MW of capacity (excluding the effect of multiple offerings from the same resource). The electronic bids were opened on November 13, 2018, in the presence of an independent accounting firm and a member of the Commission staff, with an electronic copy of each proposal being retained for future reference by the accounting firm.

Q. WHAT WERE THE MAJOR STEPS IN THE CAPACITY RFP PROCESS AFTER THE PROPOSALS WERE RECEIVED?

A. In general terms, the process consisted of the following steps. For the most part, these are set forth in chronological order, but some overlap may necessarily have occurred.

- Assessment of bids to confirm material compliance with the terms of the Capacity RFP
- Preliminary evaluation on the basis of production costs and other factors
- Initial due diligence related to proposals to acquire existing facilities
- A more detailed evaluation to derive a "Competitive Tier" of proposals
- Initial meetings with each Competitive Tier bidder, encouraging proposal and pricing updates
- Receipt of updated bid proposals, with electronic copies transmitted to the independent accounting firm for retention
- Detailed due diligence related to proposals to acquire existing facilities
- Further analysis of the updated bid proposals, including preliminary transmission costs and impacts, to determine an initial "Shortlist"
- One-on-one negotiations for projects on the Shortlist, with encouragements for proposal and pricing updates
- Further analysis to reflect updated information (e.g., bidder proposal refinements, due diligence information, transmission impacts), along with associated contract negotiations

Q. WERE THESE PROPOSALS EVALUATED IN A COMPARABLE MANNER?

A. Yes. The economic evaluations used throughout this process assessed the costs and benefits associated with the various competing proposals in a comprehensive and non-discriminatory manner. To that end, the Reliability and Resource Procurement group at SCS headed up by Mr. Looney conducted the economic evaluations for the proposals originating from bids in the Capacity RFP as well as the turnkey proposal. The evaluation of proposals for solar photovoltaic facilities paired with battery energy storage systems ("Solar/BESS") was performed by Forecasting and Resource Planning consistent with the Company's prior evaluations of solar and other renewable resources.

Q. WHY DID YOU RETAIN EVALUATION RESPONSIBILITY FOR THE SOLAR/BESS PROJECTS?

A: Given that these proposals originated from the Renewable RFP, Forecasting and Resource Planning had already begun to analyze them and therefore retained evaluation responsibility for the Solar/BESS projects to facilitate ongoing negotiations and to achieve an outcome that best satisfied Alabama Power's indicated needs.

Q: HOW WERE THE SOLAR/BESS PROJECTS EVALUATED?

A: Forecasting and Resource Planning utilized an approach comparable to that employed by Mr. Looney's group and considered the same cost components and resource benefits.

Q. EXPLAIN HOW THE SOLAR/BESS PROJECTS EVOLVED.

A. I mentioned previously that the Company conducted a Renewable RFP in 2018 in an effort to identify potentially viable renewable resources that might be candidates for certification pursuant to the Commission's order in Docket No. 32382. As discussions were ongoing in connection with some of those renewable projects, the Company received proposals for stand-alone battery storage in response to the Capacity RFP. Although the stand-alone battery storage projects were not economically viable options, the Company concluded that a pairing of such storage projects with renewable (solar) projects emanating from the Renewable RFP might together comprise cost-effective capacity resources. That idea led to the submission of various Solar/BESS proposals that, as discussed below, proved to be economically attractive when modeled along with existing system resources.

III. Portfolio of Resources Proposed for Certification

Q. DESCRIBE THE PORTFOLIO OF RESOURCES THAT WERE SELECTED FOR CERTIFICATION BY THE COMPANY, ON THE BASIS OF COST-EFFECTIVENESS AND RELIABILTY, TO MEET THE CAPACITY NEED IDENTIFIED THROUGH THE 2019 IRP PROCESS.

A. As reflected in the Petition for a Certificate of Convenience and Necessity, the resource portfolio proposed by the Company to meet the identified capacity need is as follows:

- Five (5) Solar/BESS project PPAs, with a cumulative winter capacity equivalence of 340 MW (68 MW each)
- Barry Unit 8 Combined Cycle Project, with an ultimate winter capacity rating of 743 MW
- Hog Bayou PPA, with a winter capacity rating of 238 MW
- Acquisition of Central Alabama Generating Station, with a winter capacity rating of 915 MW

These supply resources will add an additional 2236 MW to the Company's winter capacity. While largely resolving the pressing reliability need in the winter season, this total falls short of the indicated need for approximately 2400 MW by the 2023-2024 timeframe. The Company plans to address that difference through the pursuit of approximately 200 MW of new demand-side management programs and distributed energy resources that will be reflected in the next iteration of the IRP.

Q. HOW DID THE COMPANY DETERMINE THE SUPPLY-SIDE RESOURCES SHOWN ABOVE TO BE THE MOST RELIABLE AND COST-EFFECTIVE PORTFOLIO OPTIONS?

A. As discussed more fully in Mr. Looney's testimony, the detailed economic evaluation of the expected costs and benefits associated with the various proposals yielded a rank order indicative of their relative economic merit. In addition, and as he explains, a portfolio analysis was necessary to capture the potential for transmission interaction (and hence cost impacts) among the multiple proposals required to satisfy the need. I also directed Mr. Looney to examine the proposals under scenarios representing alternative fuel cost and carbon cost futures. The results of the alternative scenarios produced the portfolio reflected in the Company's petition. Appropriate regard was also given to the total amount of capacity proposed in the portfolio, as compared to the amount of need identified in the 2019 IRP.

Q. DESCRIBE EACH OF THE SUPPLY-SIDE RESOURCES IN THE PROPOSED PORTFOLIO.

A. The capacity associated with Solar/BESS projects is reflected in five PPAs with special purpose entities owned by three different developers: three projects with NextEra (Dallas County Solar, LLC, Dothan Solar, LLC and Talladega Solar, LLC), one project with Origis (AL Solar C, LLC), and one project with Southern Current (Anniston Solar, LLC). The PPAs are all structured the same, providing for a nominal 80 MW solar facility plus a nominal 80 MW BESS. Each BESS must be able to discharge 80 MW for two hours (for a total amount of stored energy of 160 MWh) so as to meet critical system peak demands. Although the BESS component of the contracts provides capacity to the Company, payments to the sellers are all energy-based. Alabama Power has the right to direct the charging and discharging of the BESS during an eight-month period each year, including both the winter and summer peak seasons. The seller is subject to liquidated damages under certain specified circumstances, including failure to meet contractual guarantees relating to actual production from the solar facility and the capacity of the BESS. These PPAs are appended to my testimony as Exhibit JBK-3, Exhibit JBK-4, Exhibit JBK-5, Exhibit JBK-6 and Exhibit JBK-7.

Barry Unit 8 is a combined cycle facility with initial capacity ratings of 726 MW (with a scheduled uprate to 743 MW) in the winter and 653 MW (with a scheduled uprate to 685 MW) in the summer. It is being constructed pursuant to a turnkey contract with Mitsubishi Hitachi Power Systems Americas, Inc. and Black & Veatch Construction, Inc., both of whom are responsible for the engineering, equipment procurement and construction activities specified in the contract. The Company (through its agent, SCS) will maintain oversight to ensure contract compliance and is also responsible for certain site-related and interconnection work. A full description of the Barry Unit 8 project is set forth in Mr. Bush's testimony, which includes relevant portions of the turnkey contract as an exhibit.

The proposed PPA between Alabama Power and Mobile Energy, LLC (an affiliate of the LS Power Development, LLC) ("Mobile"), appended to my testimony as Exhibit JBK-8, provides the Company rights to the entire capability of the Hog Bayou

Energy Center located in Mobile County, Alabama, for a total term of approximately nineteen (19) years. The Hog Bayou Energy Center is a combined cycle, natural-gas fired facility with a summer rating of 222 MW and a winter rating of 238 MW. In order to address certain near-term reliability needs, the PPA calls for an early start period beginning in 2020 through November 2023, followed by a fifteen (15) year term beginning in December 2023. Along with monthly capacity payments, Alabama Power is responsible for an energy payment that includes a charge for each unit start, plus a charge for variable O&M expenses and a fuel adjustment based on a guaranteed heat rate. (The PPA also includes a minimum availability rate.) As this is a "tolling" PPA, the Company is handling the fuel-related arrangements (commodity and transportation). Extended periods of unavailability below a specified level constitutes an event of default by Mobile, in which case Alabama Power would be entitled to termination payments.

The final supply-side component of the portfolio is the acquisition of the Central Alabama Generating Station ("Central Alabama") located near Billingsley, Alabama. Central Alabama is a combined cycle facility constructed in 2003, with a winter capacity rating of 915 MW and a summer capacity rating of 890 MW. The facility is owned by Tenaska Alabama II Partners, L.P., a Delaware limited partnership in which a Tenaska subsidiary is the managing general partner and majority owner. Until May 2023, Central Alabama is subject to a PPA with [redacted] under which it is entitled to the capacity of the facility and the associated energy. Upon the closing of a Purchase and Sale Agreement ("PSA"), Alabama Power will become the owner of Central Alabama. At that point, the facility is expected to have a remaining useful life of approximately 23 years. The terms and provisions of the above-described

PPA with [redacted] will remain in place until it expires, with Alabama Power entitled to receive the associated revenues. The Company will thereafter have the same rights and responsibilities associated with Central Alabama as with any other generating facility owned by the Company. The PSA is subject to a number of conditions, specifically including receipt of requisite regulatory approvals. The PSA, in its agreed upon form and with relevant ancillary transaction documents, is appended to my testimony as Exhibit JBK-9. The PSA is not yet signed by the parties, but execution is forthcoming. At an appropriate time, the Company will supplement this exhibit to reflect finalization.

Q. DESCRIBE THE DEMAND-SIDE MANAGEMENT AND DISTRIBUTED ENERGY RESOURCE PROGRAMS THAT THE COMPANY SEEKS TO PURSUE.

A. As set forth in the petition, the Company is requesting authorization to pursue an increase of 200 MW in demand-side management and distributed energy resource programs. At this time, the Company does not know the mix of programs it will seek to implement; however, examples of potential demand-side management programs include:

- A smart thermostat program, coupled with the deployment of high efficiency heat pumps;
- An "Orchestrated Energy" program, by which the Company would incent the shifting of load from higher cost periods to lower cost periods; and
- Expansion of existing standby generation, non-firm, load shifting and critical peak pricing programs.

Q. WHAT DISTRIBUTED ENERGY RESOURCE PROGRAMS IS THE COMPANY CONTEMPLATING?

A. Here too, the Company's program evaluation remains ongoing. The Company envisions, however, the potential for deployments both at a utility scale level as well as smaller scale facilities (e.g., less than 1 MW), all at customer locations.

Q. DOESN'T THE COMPANY HAVE AN EXISTING CERTIFICATE FOR SUCH PROJECTS?

A. The Commission did authorize a blanket certificate for renewable generation and environmentally specialized resources in 2015 in Docket No. 32382. By its terms, that certificate expires in 2021, which is during the triennial cycle of the Company's integrated resource plan. The Company may separately elect to pursue renewal of that certificate, but in connection with the current need-based petition, the Company seeks to obtain appropriate authorization now so that it can proceed forward with program development.

Q. HOW DOES THE COMPANY PROPOSE TO IMPLEMENT ITS DEMAND-SIDE MANAGEMENT AND DISTRIBUTED ENERGY RESOURCE PROGRAMS?

A. Similar to the projects under the renewable generation certificate, the Company would submit the demand-side management and distributed energy resource programs for Commission approval on a project-by-project basis. For each project, Alabama Power's evaluative criteria would be that the project results in positive benefit for all customers over the term of the project relative to the applicable benchmark plan, taking into account the costs and revenue impacts of the project and the expected value corresponding to the avoided capacity addition, along with other positive benefits that may accrue through load growth, load retention or other relevant considerations associated with the particular project.

Q. DO YOU HAVE ANY CONCLUDING REMARKS RELATED TO THE COMPANY'S PETITION AND ASSOCIATED TESTIMONY?

A. As demonstrated in my testimony and that of the other witnesses, the Company's petition is fully supported in all respects. There is the clear showing of a need for additional capacity resources that will enable Alabama Power to continue to fulfill its duty to provide reliable service to its customers. The testimony further shows that the Company has selected a portfolio that constitutes a reasonable and cost-effective means of satisfying that need.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**
	)
Petitioner	**)**

DIRECT TESTIMONY OF JOHN B. KELLEY
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF JEFFERSON)

John B. Kelley, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

John B. Kelley

John B. Kelley

Subscribed and sworn to before me
this 4th day of September, 2019.

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

Notary Public

Direct Testimony of John B. Kelley

Exhibit JBK-1

PUBLIC VERSION

Alabama Power

PUBLIC VERSION

2019 Integrated Resource Plan Summary Report

Public Version

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EXECUTIVE SUMMARY

The 2019 Integrated Resource Plan ("2019 IRP")[1] for Alabama Power Company ("Alabama Power" or "Company") is a comprehensive process that serves as the foundation for certain decisions affecting the Company's future portfolio of supply-side and demand-side resources.[2] The IRP process does not produce binding determinations concerning new specific resources that the Company will procure in the future. Rather, it is a management tool that, using the best information currently available, facilitates the Company's ability to make future resource decisions that result in reliable and cost-effective electric service to customers, while accounting for risks and uncertainties inherent in planning for resources sufficient to meet expected customer demand. The dynamic nature of the Company's IRP process thus produces a comprehensive plan of indicative resource additions that serves as the basis on which the Company can develop and manage its portfolio of supply-side and demand-side management ("DSM") resources to provide reliable electric service to its customers.

The IRP is developed on a formal basis every three years and is reviewed with the staff of the Alabama Public Service Commission ("APSC"). This review keeps the APSC informed as to the timing of needed resource additions, while also helping to ensure that the process yields results that are consistent with the Company's ultimate goals of minimizing rates and providing the desired level of service reliability. These goals are important because they allow the Company to be competitive with other energy providers and promote economic development within the State of Alabama.

Alabama Power remains committed to maintaining a diverse supply-side generating portfolio, along with cost-effective DSM resources that benefit all customers. Resource diversity on the supply side, which includes nuclear, natural gas, coal, oil, hydroelectric, wind, solar, and biomass resources, provides significant benefit to customers, as it enables the Company to adapt to changes impacting its energy supply obligations. In that regard, the Company's generating fleet is transitioning due to a number of factors, including the cost of natural gas and the cost impacts of various environmental regulations

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[1] As noted, the IRP is a comprehensive, data-intensive process that ultimately yields an indicated list of future resource additions designed to meet appropriate reliability requirements in a cost-effective manner. This Summary Report only serves to overview that process and summarize its results; however, for ease of reference this document is sometimes referred to as the "2019 IRP".

[2] Appendix 1 is a detailed list of all supply-side resources owned and controlled by Alabama Power. Appendix 2 summarizes the Company's activities related to existing and potential Demand Side Management ("DSM") programs.

by the U.S. Environmental Protection Agency ("EPA"). A recent example of an environmentally-driven change is the retirement of Gorgas Units 8-10 due to the compliance requirements of EPA's coal combustion residuals rule (Disposal of Coal Combustion Residuals from Electric Utilities, or "CCR Rule"). Ongoing uncertainties also persist in connection with EPA's Effluent Limitation Guidelines rule addressing wastewater limits for steam electric power plants, as well as initiatives at the federal level to regulate or tax carbon dioxide ("CO2") emissions. The cost and operating implications for the Company's supply resources related to these and other considerations remain factors in the Company's planning scenarios related to the 2019 IRP.

As reflected in the 2019 IRP, Alabama Power's planning process now separately considers the winter and the summer seasons, thereby ensuring sufficient reserve capacity during different times of the year, as compared to a focus solely on summer reliability. Historically, the Company's capacity planning decisions have been driven by summer peak loads and a corresponding summer-focused Target Reserve Margin. These planning techniques have proven to be successful in supporting reliability, while cost-effectively meeting the needs of customers. However, operational experience over the last several years, and in particular a winter peak demand for the Alabama Power system, demonstrates a significant transition in reliability risk from the summer-only season to predominantly the winter season. As a result, Alabama Power is modifying its summer-based capacity planning approach to specifically address reliability on a seasonal basis. Seasonal planning provides greater visibility into capacity needs in both summer and winter, rather than limiting reliability decisions to a single season.

In support of the transition to seasonal planning, the 2019 IRP reflects the results of the most recent Reserve Margin Study for the Southern Company System ("System"). The Reserve Margin Study provides a detailed reliability analysis that yields Target Reserve Margins for the System. Based upon the Reserve Margin Study, the Company is utilizing seasonal Target Reserve Margins for all future planning purposes. For long-term planning starting in 2022 and beyond, the Company's plan maintains a System Target Reserve Margin of 16.25 percent for summer periods ("Summer Target Reserve Margin"). For winter periods, the Company is adopting a long-term planning Target Reserve Margin for the System of 26 percent ("Winter Target Reserve Margin"). Consistent with past practice, the Company also evaluated the short term (2019-2021) Target Reserve Margin and for planning purposes is adopting a 15.75 percent target for summer and a 25.5 percent target for winter. Due to the benefits of load diversity, coordinated planning and operations, and the ability to share resources, the Southern Company retail operating companies can together achieve these System targets by each utilizing diversified reserve margins that are lower than the Target Reserve Margins for the System. Thus, the diversified Summer Target Reserve Margins for Alabama Power are 14.89 percent over the long-term and 14.39 percent over the short-term. Likewise, Alabama Power's diversified Winter Target Reserve Margins are 25.25 percent over the long-term and 24.75 percent over the short-term. These diversified values are subject to change in response to changes in System load diversity. Figure ES-1 compares the previous planning reserve margin targets to those predicated on the updated Reserve Margin Study.

FIGURE ES-1: Summer and Winter Target Planning Reserve Margin Comparison

	Previous Reserve Margin Study	Updated Reserve Margin Study
System Long-Term Target Planning Reserve Margin (Summer)	16.25%	16.25%
System Short-Term Target Planning Reserve Margin (Summer)	14.75%	15.75%
Diversified Long-Term Target Planning Reserve Margin (Summer)	14.74%	14.89%
Diversified Short-Term Target Planning Reserve Margin (Summer)	13.26%	14.39%
System Long-Term Target Planning Reserve Margin (Winter)	-	26.00%
System Short-Term Target Planning Reserve Margin (Winter)	-	25.50%
Diversified Long-Term Target Planning Reserve Margin (Winter)	-	25.25%
Diversified Short-Term Target Planning Reserve Margin (Winter)	-	24.75%

Based on these Target Reserve Margins, and taking into account the Company's load forecast and other considerations reflected in the 2019 IRP, Alabama Power projects a resource deficit as of [redacted] longer-term resources need to be procured to address the Company's deficit in winter 2024 and

[3] *The Southern Pool is governed by the terms of the Southern Company System Intercompany Interchange Contract, which is a rate schedule on file with the Federal Energy Regulatory Commission ("FERC"). Well-recognized benefits of pooling include lower production costs for the participants (as opposed to stand-alone operation), lower reserve margins due to load diversity, and the ability to take advantage of economies of scale by sharing temporary surplus and deficit capacity.*

beyond. To meet this need, the Company will continue to employ the principles discussed earlier to identify an economic set of resource options that are projected to provide the most benefit to customers at the lowest practicable cost. Upon identification of these resources, the Company will seek authorization from the APSC for procurement or development rights, as applicable.

I. INTRODUCTION AND OVERVIEW

Alabama Power is an investor-owned electric utility, organized and existing under the laws of the State of Alabama, and is a subsidiary of the Southern Company. In addition to Alabama Power, the Southern Company is the parent of Georgia Power Company, Mississippi Power Company, and Southern Power Company (collectively, the "Operating Companies"), as well as certain service and special-purpose subsidiaries. Alabama Power is primarily engaged in generating, transmitting and distributing electricity to the public in a large section of Alabama. The Company's retail rates and services are regulated by the APSC under the provisions of Title 37 of the Code of Alabama.

The Company has approximately 1.48 million customers, of which approximately 86 percent (1.27 million) are residential; 13.5 percent (200,000) are commercial; and 0.5 percent (6,900) are industrial and other. Alabama Power has approximately 1.57 million transmission and distribution poles, and approximately 85,000 miles of wire. The Company strives to maintain cost-effective and reliable service to its customers. For the years 2017-2018, the Company had a service reliability of 99.98 percent. As noted earlier, Alabama Power has a diverse mix of supply-side (both owned and contracted) and demand-side resources, including hydroelectric, natural gas, nuclear, coal, oil, renewable projects,[4] combined heat and power, and DSM programs.

As of April 2019, Alabama Power's supply-side capacity resources had a winter generating capability of approximately 12,600 MW and a summer generating capability of approximately 12,500 MW. These resources, along with active DSM programs having a capacity value of approximately 1,200 MW, represent a diverse mix of capacity totaling nearly 14,000 MW, as demonstrated in the following chart. A more detailed breakdown of the Company's generating and demand side resources is presented in Appendices 1 and 2.

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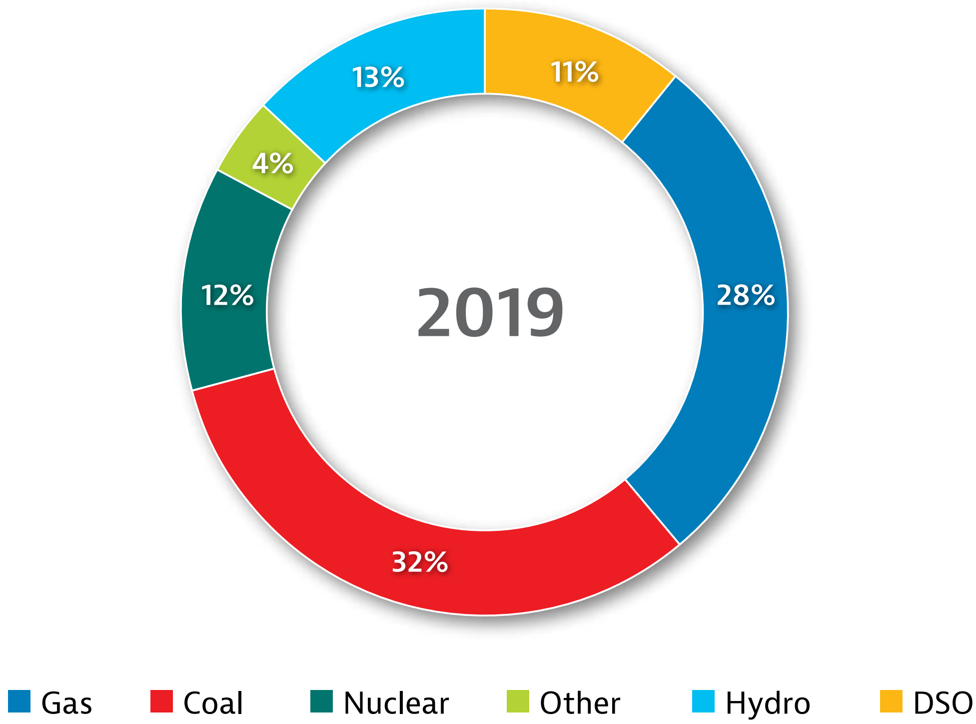
[4] As applicable to all references of renewable projects in this 2019 IRP, the Company has rights to the environmental attributes, including the renewable energy certificates ("RECs"), associated with the energy from these projects. Alabama Power can choose to retire some, or all, of these environmental attributes on behalf of its retail electric customers, or it can sell the environmental attributes, either bundled with energy or separately, to third parties. Included in Appendix 1 is a listing of the Company's contracted or owned renewable projects. Appendix 3 provides an overview of the Company's efforts directed to the procurement of renewable resources.

Figure I-1: Alabama Power Capacity Mix



This document summarizes the results of Alabama Power's 2019 IRP and describes the process used in its development. As noted at the outset, the IRP serves as the foundation for certain decisions affecting the Company's portfolio of generating resources, facilitating the Company's ability to provide reliable and cost-effective electric service to its customers. At the most basic level, the IRP yields an indicative annual schedule of integrated supply-side and demand-side resource additions to accomplish the aforementioned objectives, consistent with the Company's duties and obligations to the public as a regulated public utility. The Company's IRP is performed through a coordinated process utilized across the Southern Company retail operating companies, with the assistance of their agent, Southern Company Services, Inc. ("SCS"). The process used by Alabama Power to develop the IRP comports with the provisions of the Public Utility Regulatory Policies Act of 1978, as amended, which contemplates the use of appropriate integrated resource planning by electric utilities.

Together with the other Operating Companies, Alabama Power participates in the Southern Pool, which provides for coordinated system operations and centralized unit commitment and joint dispatch of the Operating Companies' respective generating units.[5] In order to take advantage of economies of scale, the retail Operating Companies engage in the coordinated planning of their respective resource additions; however, each such operating company retains final decision-making authority with regard to any resource additions that it may require, consistent with its respective duty of service as provided by law.

The System is represented on the Southeastern Electric Reliability Council ("SERC"), which serves to coordinate operations and other measures to maintain a high level of reliability for the electric system in the Southeastern United States. Likewise, Alabama Power and the other retail Operating Companies, along with other transmission owners in the region, are sponsors of the Southeastern Regional Transmission Planning process, which provides an open, coordinated, and transparent transmission planning process for much of the Southeast in accordance with the requirements of FERC.

In order to anticipate future energy and demand requirements of the customers it serves, Alabama Power develops a load forecast that comprises a 20-year projection of the expected growth in customer requirements. Using the best information reasonably available, the Company then develops an IRP that reflects the indicated optimal mix of supply-side and demand-side resources to meet this projected customer peak demand in a reliable and cost-effective manner. Alabama Power has traditionally been considered summer peaking, meaning its annual peak demand falls during the summer months; however, its customer demands have been growing in the winter months. Indeed, in recent years, Alabama Power's weather-normalized winter peak demand has exceeded its summer peak demand, and its most recent load forecast projects a predominant winter peak demand. The Company's load forecast is discussed further in Section III.B.

[5] *On January 1, 2019, Gulf Power Company was sold to NextEra Resources and is no longer a subsidiary of the Southern Company. During a transition period, Gulf Power will continue to participate in the Southern Pool, but is no longer a part of coordinated planning by the remaining retail operating companies.*

II. ENVIRONMENTAL STATUTES AND REGULATIONS[6]

II.A. General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations that impact air, water, and land resources. Applicable statutes include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning and Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these and other environmental requirements involves significant capital and operating costs. Through 2018, the Company had invested approximately $5.4 billion in environmental capital retrofit projects to comply with these requirements. The Company currently expects that capital expenditures to comply with environmental statutes and regulations will total approximately $635 million from 2019 through 2023. These estimates do not include any potential compliance costs associated with pending regulation of CO2 emissions from fossil fuel-fired electric generating units. The Company also anticipates costs associated with closure in place and groundwater monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation ("ARO") liabilities.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and the outcome of any associated legal challenges; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. To date, the Company's compliance strategy in response to federal environmental requirements has resulted in a reduction of more than 2,100 MW of coal-fired capacity, due either to fuel switching, the retirement of units, or the placing of units on inactive reserve. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units.

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[6] The information in this section is drawn from the combined annual report on Form 10-K of The Southern Company and the Operating Companies for the year ended December 31, 2018, as filed with the Securities and Exchange Commission. Any material difference between the information contained therein and this section is unintended and the annual report should be referenced as the controlling discussion.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be known with certainty until the applicable legislation or regulation is finalized, legal challenges are resolved, and any necessary rules are implemented at the state level. In any case, such governmental mandates could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Many of the Company's commercial and industrial customers may also be affected by such future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

II.B. Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Additional controls to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements may become necessary in the future, depending on further actions taken by the EPA.

In 2012, the EPA finalized the Mercury and Air Toxics Standards ("MATS") rule, which imposed stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units ("EGUs"). The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule included emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each Company unit. In June 2015, the Supreme Court issued a decision finding that, in developing the MATS rule, the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant ("HAP") emissions from EGUs. In December 2015, the D.C. Circuit remanded the MATS rule to the EPA without vacatur to respond to the Supreme Court's decision. The EPA's supplemental finding in response to the Supreme Court's decision, which was finalized in April 2016, did not have any impact on the MATS rule compliance requirements or deadlines.

On December 26, 2018, the EPA proposed to revise the Supplemental Cost Finding for MATS. The EPA proposes to correct what it identifies as flaws in the 2016 cost/benefit analysis it used to regulate HAPs from coal- and oil-fired EGUs. The EPA has now determined that the direct benefits from regulating HAPs from EGUs are grossly outweighed by the costs and consequently, it is not "appropriate and necessary" to regulate EGU HAP emissions. However, the EPA is not proposing to rescind MATS, and it reasons that MATS will remain in place based on its interpretation of 2008 D.C. Circuit Court decisions. In a companion action, the EPA is also proposing that remaining risks associated with EGU HAP emissions are acceptable and therefore, more stringent standards under MATS are not warranted.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard ("NAAQS"). In 2015, the EPA adopted a revised eight-hour ozone NAAQS and in 2017 published its final area designations for Alabama. All areas within the Company's service territory have achieved attainment of the 2015 ozone standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS, and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA completed final designations for the 2012 annual standard for Alabama in March 2015, and no new nonattainment areas were designated within the Company's service territory.

Final revisions to the NAAQS for sulfur dioxide ("SO2"), which established a new one-hour standard, became effective in 2010. In January 2017, the Company submitted modeling showing attainment of the SO2 standard in the vicinity of its coal-fired generating plants. Based on this modeling analysis, the EPA did not designate any area in Alabama as nonattainment for this standard. On May 25, 2018, in its review of the SO2 ambient air quality standard, the EPA proposed to retain the existing level of the standard.

In February 2014, the EPA proposed to delete from the Alabama State Implementation Plan ("SIP") the Alabama opacity rule that the EPA approved in 2008. This action by the EPA, which provides operational flexibility to affected units, was in response to a 2013 ruling by the U.S. Court of Appeals for the Eleventh Circuit that vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act.

In 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") to address impacts in downwind states of SO2 and nitrogen oxide ("NOX") emissions from fossil fuel-fired electric generating plants. CSAPR established emissions trading programs and allowance budgets for certain states and allocates emissions allowances for sources in those states, including Alabama. In 2016, the EPA published a final CSAPR Update rule, establishing more stringent ozone season NOX emissions budgets for several states, including Alabama. On December 6, 2018, the EPA finalized the "CSAPR Close-Out" rule regarding interstate transport requirements for the 2008 ozone standard. The EPA determined that the 20 states affected by the CSAPR Update rule (including Alabama) have fully met their interstate transport obligations and that emissions from these states do not contribute significantly to any downwind state's ability to meet the 2008 ozone standard. The Company is complying with CSAPR and operating its units within the emissions allowances allocated to the Company under all CSAPR allowance programs.

The EPA finalized regional haze regulations in 2005 and 2017. These regulations require states, tribal governments, and various federal agencies to develop and implement plans to reduce pollutants that impair visibility and demonstrate reasonable progress toward the goal of restoring natural visibility conditions in certain areas, including national parks and wilderness areas. In December 2018, the EPA proposed to approve the State of Alabama's progress report for the first regional haze planning period. Alabama must also submit to the EPA by July 31, 2021 a revised SIP, demonstrating continued reasonable progress towards achieving visibility improvement goals. These plans could require reductions in certain pollutants, such as particulate matter, SO2, and NOX, which could result in increased compliance costs. Regional haze regulations also involve the application of Best Available Retrofit Technology ("BART") to sources including certain Company generating units. What constitutes BART has been the subject of litigation and is still an unresolved issue for some units operated by the Company and thus the ultimate impact from BART requirements is currently unknown.

In 2012, the EPA published proposed revisions to the New Source Performance Standard ("NSPS") for

Stationary Combustion Turbines ("CTs"). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units) during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In June 2015, the EPA published a final rule requiring certain states (including Alabama) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction ("SSM") by no later than November 2016. In ensuing litigation, the EPA filed a motion with the D.C. Circuit to hold the matter in abeyance while the agency conducts a review. The court granted EPA's motion and the agency is reconsidering its SSM policies and guidance.

II.C. Water Quality

In November 2015, the EPA published the final effluent limitations guidelines rule that imposes stringent technology-based requirements for certain wastestreams from steam electric power plants ("2015 ELG Rule"). The 2015 ELG Rule requires major changes to wastewater treatment systems at coal-fired plants, with stringent restrictions affecting the disposition of fly ash transport water ("FATW"), bottom ash transport water ("BATW"), and flue gas desulfurization ("FGD" or "scrubber") wastewater. The new effluent limits will be implemented in National Pollutant Discharge Elimination System ("NPDES") permits issued by the Alabama Department of Environmental Management ("ADEM"), with applicability based on relevant information provided by the facility (as early as November 1, 2018, but not later than December 31, 2023). However, uncertainty surrounds certain portions of the 2015 ELG Rule, as the EPA is scheduled to issue a new rulemaking by spring of 2020 that could revise the limitations and/or applicability dates for BATW and FGD wastewater. The impact of any changes to the 2015 ELG Rule will depend on the content of the new rule and the outcome of any legal challenges.

Another part of the Clean Water Act ("CWA") applicable to Alabama Power is Section 316(b), which requires that "the location, design, construction and capacity of cooling water intake structures reflect the best technology available ["BTA"] for minimizing adverse environmental impact." After a series of rulemakings and court cases extending all the way to the U.S. Supreme Court, a final rule was published in the Federal Register in August 2014, establishing impingement mortality and entrainment requirements for existing power generating facilities and manufacturing and industrial facilities that are designed to withdraw more than two million gallons of water per day from waters of the United States and use at least 25 percent of that water exclusively for cooling purposes ("316(b) Rule"). The new rule became effective in October 2014. Compliance is required "as soon as practicable" according to the schedule of requirements set by the permitting authority. NPDES permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. With the recent issuance of the Greene County NPDES permit renewal, ADEM has required any remaining Section 316(b) studies to be submitted in the next 5-year permit cycle. Alabama Power has begun conducting these studies and currently anticipates that changes to Cooling Water Intake Structures ("CWIS") may include fish-friendly CWIS screens with fish return systems and the addition of minor monitoring equipment at certain plants. However, the ultimate impact of the 316(b) Rule will depend on the outcome of these plant-specific studies and any additional protective measures required by ADEM to be incorporated into each plant's NPDES permit renewal in the next permit cycle, based on site-specific factors.

In June 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of Waters of the United States ("WOTUS") for all CWA programs. The final rule significantly expanded the scope of federal jurisdiction under the CWA and could have a material adverse impact on economic development projects, which could affect growth in customer demand. In addition, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines. Moreover, in 2019, the EPA and the Army Corps of Engineers are anticipated to publish a final rule to replace the WOTUS definition established in 2015. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any challenges.

II.D. Coal Combustion Residuals

In 2015, the EPA finalized the CCR Rule, which established non-hazardous solid waste regulations for the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments (ash ponds) at active generating power plants. Among other things, the CCR Rule requires CCR units to be evaluated against a set of performance criteria. The State of Alabama has also finalized its own regulations regarding the handling of CCR. In April 2019, Alabama Power initiated closure of its unlined CCR impoundments and ash ponds.

II.E. Climate Issues

On July 8, 2019, the EPA published the final version of the Affordable Clean Energy ("ACE") Rule, which is to replace a regulation enacted in 2015 (the "Clean Power Plan" or "CPP") that would limit CO2 emissions from existing fossil fuel-fired EGUs. The CPP has been stayed by the U.S. Supreme Court since February 2016. The ACE Rule would require states to develop unit-specific CO2 emission rate standards based on heat-rate efficiency improvements for existing coal-fired steam units. Under the final rule, combustion turbines, including natural gas combined cycles units, are not affected sources. Alabama Power owns seven coal-fired steam units to which the ACE Rule is applicable. The ultimate impact of this rule on Alabama Power is currently unknown and will depend on subsequent state plan developments and requirements, along with any associated legal challenges.

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule ("2015 NSPS Rule"). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units, which includes stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS Rule by not basing the new and reconstructed fossil-fired steam boiler and integrated gasification combined cycle ("IGCC") standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

Separate and apart from these regulations, the prospect remains for federal legislation imposing a tax on carbon emissions or establishing a national cap and trade carbon emission allowance system. As with other environmental requirements, any legislative or regulatory action directed to CO2 emissions could result in significant additional capital expenditures or compliance costs for the Company, and thus affect future unit retirement and replacement decisions.

III. INTEGRATED RESOURCE PLAN

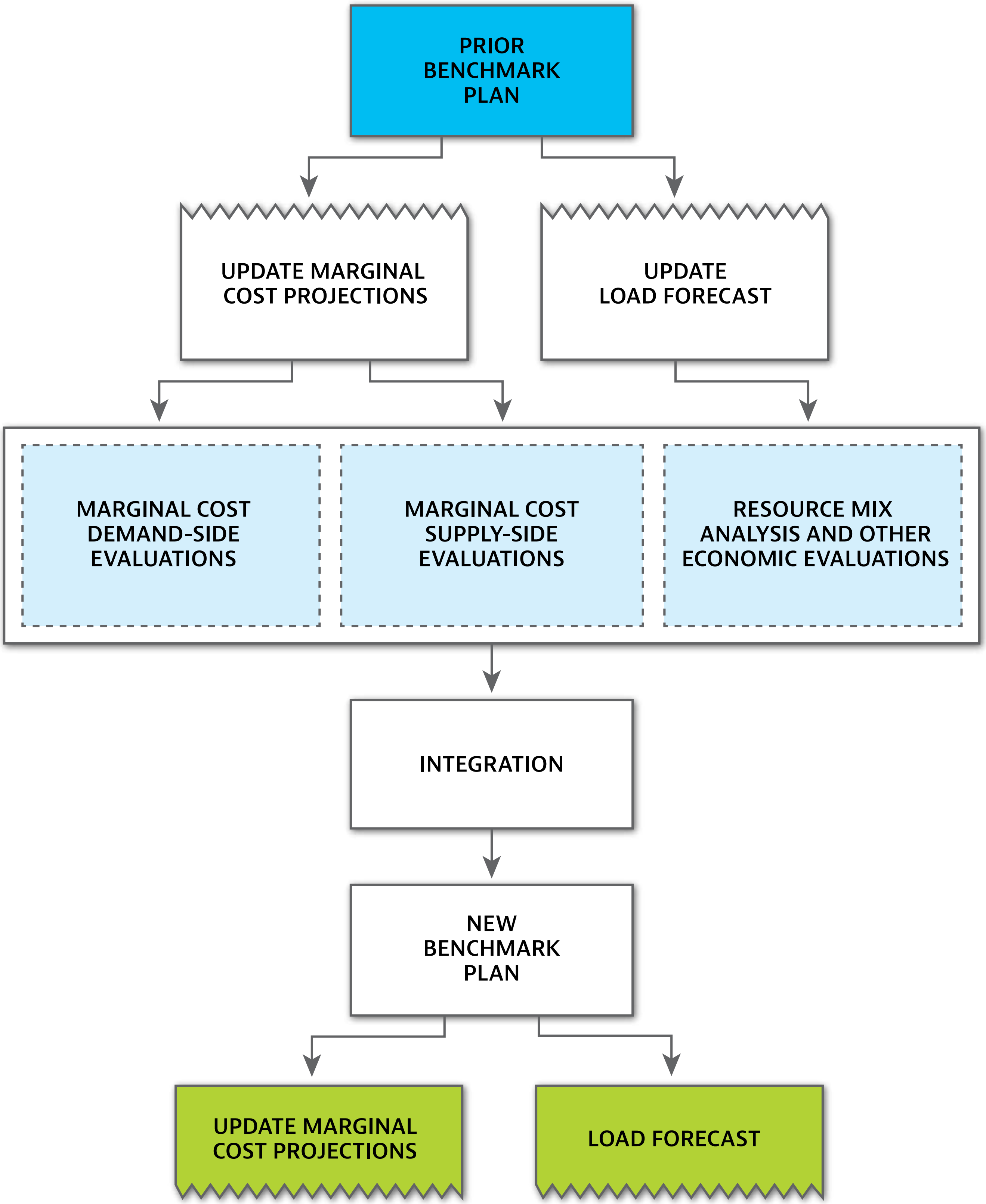
III.A. Process Overview

The integrated resource planning process is designed to identify the timing, amount, and types of resources necessary to serve the long-term energy and demand requirements of Alabama Power's customers. Aided by the IRP, the Company is able to develop and implement a resource strategy that is reasonably expected to provide for cost-effective and reliable service.

The 2019 IRP, which has a 20-year planning horizon, indicates the optimal mix of resources necessary to meet customers' future load requirements. Using the best information available at the time of its development, the IRP provides the basis for estimating potential capital expenditures that may be required for future generating capacity additions. In the IRP, both supply-side and demand-side options are evaluated and integrated on a consistent basis using marginal cost analysis. This approach ensures that both options are identified for potential selection and deployment when such options represent a viable economic choice.

As shown in Figure III-A-1, integrated resource planning is an iterative process that evaluates existing and potential resource options in an effort to identify the best combination, in terms of reliability and expected total cost for serving customers.

FIGURE III-A-1: Alabama Power IRP Process



The principal components in the process are as follows:

Update Marginal Cost Projections Based on Latest IRP

Marginal cost projections are derived using the previous IRP. These projections are then updated to recognize any significant changes in costs such as fuel, technology, and regulatory compliance.

Load Forecast

A forecast of future energy and peak demand requirements for the next 20 years is developed. This forecast incorporates an estimate of future economic conditions and trends in customer energy usage.

Marginal Cost Demand-Side Evaluations

DSM programs (also referred to as demand-side options, or “DSOs”) are evaluated on a marginal cost basis. This procedure is used to identify cost-effective DSM programs for inclusion in the IRP.

Marginal Cost Supply-Side Evaluations

Marginal cost evaluations are performed to determine if modifications to existing supply-side resources or power purchases from other suppliers are economically viable.

Resource Mix Analysis and Benchmark Evaluations

This part of the IRP process involves the development of an optimal resource mix. The resource mix is a flexible, iterative analysis that allows for integration of the appropriate combination of resources that will serve the projected load at the lowest expected total cost (both fixed and variable), while maintaining the target reliability guideline. This step includes sensitivity analyses to establish boundaries within which the conclusions of a benchmark plan remain valid.

The resource mix analysis incorporates the impacts of existing and projected DSM programs, revised load information, and updated cost information (including fuel, capital, operation and maintenance). It also incorporates the most recent information on the characteristics of existing resources, both supply-side and demand-side, as well as changes such as expected in-service dates of resource additions, the expiration of PPA resources, and assumptions regarding future resource availability.[7] The flexibility of the IRP process allows insertion of marginal cost results from the supply-side or demand-side options in any sequence. The result is a benchmark plan that identifies the most cost-effective combination of options, which in turn informs the Company's decision-making as it seeks to acquire or develop resources to address future needs.

In planning future resource additions, consideration is given to uncertainties associated with unforeseen unit outages, abnormal weather, and load forecast deviations. In order to minimize the effects of these uncertainties, criteria are established that qualify and quantify an appropriate level of capacity reserves in both the summer and winter seasons. These reserves are planned to be available to account for the potential inability to meet load requirements due to generation shortfalls resulting from uncertainties inherent in the resource planning process. The minimum long-term target reserve margin guideline, which is periodically reviewed and re-evaluated, is based on risk-adjusted economic analyses, operating experience and system operation input, and seeks to minimize the combined cost of new generating capacity, production costs, and customer-related costs associated with outages while also ensuring the Company meets minimum reliability criteria thresholds.

Consistent with the updated Reserve Margin Study (discussed in greater detail in Section III.D), the 2019 IRP utilizes a minimum long-term Summer Target Reserve Margin of 16.25 percent for summer periods and 26 percent for the minimum long-term Winter Target Reserve Margin. By virtue of load diversity across the Southern System, the Summer Target Reserve Margin can be met if each Operating Company maintains a long-term summer reserve margin of at least 14.89 percent. Similarly, the Winter Target Reserve Margin can be met if each Operating Company maintains a long-term winter reserve margin of at least 25.25 percent. In other words, Alabama Power can maintain a long-term winter reserve margin of 25.25 percent but realize a level of reliability equivalent to 26 percent, thereby avoiding the cost of building or purchasing additional resources associated with the 0.75 percent differential. These capacity savings represent one of the many recognized benefits of operating as part of the Southern Pool.

[7] *These assumptions are for study purposes only and do not reflect management decisions regarding the actual useful lives of such resources.*

Integration

Demand-side and supply-side options identified as cost-effective choices for resource additions, but not previously reflected in the prior IRP's benchmark plan, are incorporated in the IRP during the integration phase. This phase consists of determining the Company's best alternative for meeting the resource needs identified in the benchmark plan, coordinating resource additions with those of the other retail Operating Companies, and performing a financial assessment of the plan.

The process described above is not necessarily set forth in chronological order, as many evaluations are performed concurrently. Marginal cost evaluations can be performed or updated at several points in the process.

III.B. Load Forecast

The Company annually produces a short-term and long-term energy and peak demand forecast for territorial customers of Alabama Power, including projections of customer growth, peak demand (MW), and monthly energy consumption (kWh). The 2019 IRP reflects a 20-year load forecast for the years 2019 through 2038.

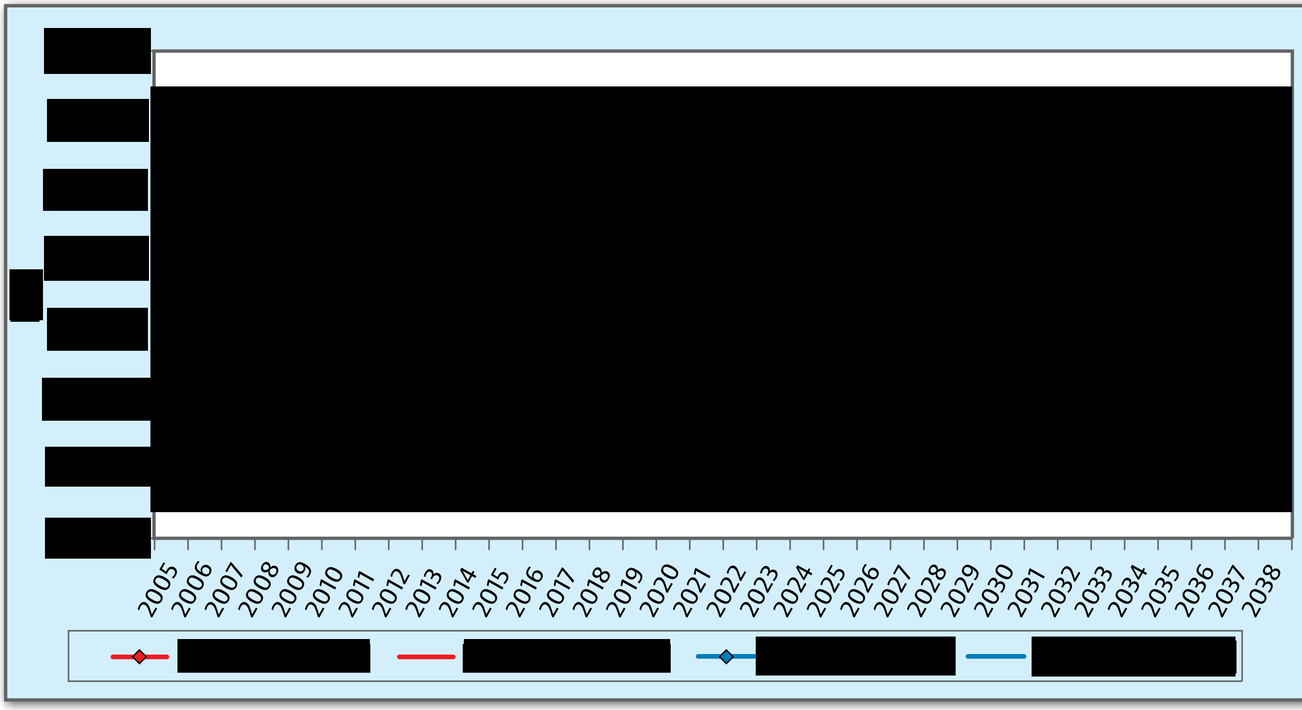
Underlying this load forecast are economic data and forecasts supplied by IHS Markit. This information includes available employment and demographic data as well as other economic indicators for the state, all of which support the development of econometric models used to forecast the number of customers, which is a major input to the load forecasting process. The other major input, per customer electricity consumption, is less correlated with economic growth and more related to trends in increased efficiency and other factors that are resulting in a decline in usage.

Alabama Power has traditionally been considered summer peaking, meaning its annual peak demand has occurred during the summer months. However, in recent years, Alabama Power's winter peak demand has exceeded the summer peak demand. The 2014 actual winter peak was 12,610 MW (prior to the utilization of interruptible and demand management options), which exceeded the prior all-time peak of 12,496 MW that occurred in the summer of 2007. Indeed, weather normalization studies indicate that the weather adjusted winter peak has exceeded the weather adjusted summer peak since 2010. The Company's most recent load forecast projects a winter peak demand that is between [redacted] than the summer peak demand.

Figure III-B-1 represents the Company's weather normalized historical summer and winter peak demands since 2005, and clearly shows that weather adjusted winter peaks began to exceed summer peaks as early as 2010. The graph also illustrates the Company's forecasted winter and summer peak demands from 2019 through 2038. [redacted] These projected rates are lower than those shown in the 2016 IRP, and reflect the effects of a slower economic growth in the near term and, over the long term, [redacted] greater penetration of appliance and lighting efficiencies.

PUBLIC VERSION

FIGURE III-B-1: Alabama Power Weather Normalized Historical Peak Demand with Forecast



	[redacted]		[redacted]	
Year	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]		[redacted]	
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]

2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]

These forecast results are heavily dependent on the level of expected economic activity and continued employment growth in the State of Alabama. Another influencing factor is continued exports of products produced in Alabama (primarily transportation equipment), which is an important consideration as Alabama remains a heavy manufacturing state.

III.C. Fuel Forecast

Both short-term (current year plus two) and long-term (year four and beyond) fuel and allowance price forecasts are developed for use not only in the Company's planning activities, but also in its business case analyses and other applicable decisions. Short-term forecasts are updated monthly as part of the Company's fuel budgeting process and marginal pricing dispatch procedures. The long-term forecasts are developed each year for use in the Company's planning activities. Charles River Associates ("CRA"), the Company's scenario modeling consultant, produces the long-term fuel price forecasts for natural gas and coal.

The development of the long-term forecasts is a highly collaborative effort between CRA, SCS, and the retail Operating Companies. CRA's MRN-NEEM national, multi-sector, energy-economy model, with support from other CRA models, is used to generate integrated results for natural gas and coal prices, in five-year increments, for the period 2023 through 2058. The integrated modeling approach makes it possible to develop forecasts for natural gas and coal prices that are internally consistent with one another and with other variables and feedbacks involving economic growth, electricity consumption, and output across many sectors and regions. The integrated approach takes a set of assumptions about market fundamentals and then solves for the prices that make the quantity supplied equal to the quantity demanded in all markets. In addition, the integrated approach simulates interactions among different markets and thereby reveals how such things as environmental regulations and natural gas supply outlooks shape the disposition of economic output across sectors, as well as the competition between coal and natural gas as a generation fuel.

III.D. Reserve Margin

Electric utility customers expect and depend on a high level of service reliability. Accordingly, a retail electric utility should have an economically balanced margin of generating capacity above its anticipated peak load—the reserve margin. This enables the utility to maintain sustained reliability for its customers, notwithstanding unexpected events such as equipment failures or extreme weather. Reserve planning must be done on both a short-term and long-term basis, as the processes to procure additional capacity can take several years. A reserve margin study facilitates the identification of an appropriate amount of reserve capacity that should be targeted for any point in the future.

As for the System specifically, the maintenance of sufficient reserve capacity allows the Operating Companies to serve customer demand reliably, even with the prevalence of unpredictable conditions that can affect customer demand.

- **Weather Uncertainty:** The System's "weather-normal" load forecasts are based on average weather conditions over more than forty years. If the weather is hotter than normal during warm seasons or colder than normal during cold seasons, the load will be higher. The System's peak demand can be as much as 6.6 percent higher in a hot summer year and 22 percent higher in a cold winter year than in an average year.

- **Economic Growth Uncertainty:** It is difficult to project exactly how many new customers will request electric service or how much power existing customers will use from season to season. Based on historical projections and actual economic growth, peak demand may grow [redacted]

- **Unit Performance:** While the Operating Companies maintain low forced outage rates for their respective units, there have been occasions in the last ten years when [redacted]

[redacted] of the capacity of the System has been in a forced outage state concurrently.

- **Market Availability Risk:** The ability to obtain resources on short notice from the market when needed to address a System resource adequacy issue is uncertain. In general, having access to resources in neighboring regions enhances a region's reliability due to load and resource diversity. However, the amount, cost, and deliverability of those resources are subject to the external region's resource-adequacy situation or transmission constraints at any given time. While a region can expect some level of support from its neighbors, each region must carry adequate reserves and manage its own reliability risks. This necessarily results in an element of uncertainty regarding the availability of such external support when it is needed.

While each of these four factors creates a need for capacity reserves on its own, a confluence of all these risk factors poses considerable risk. Very high capacity reserves would be required to meet customers' load demands plus operating reserve requirements to address the simultaneous occurrence of all such events. However, the maintenance of such high levels of capacity reserves, in an effort to eliminate all reliability risk, would come at significant expense.

A more appropriate approach to establish a reasonable reserve margin is to minimize the combined costs of maintaining reserve capacity, system production costs, and customer costs associated with service interruptions, and then adjust for the value at risk. This approach results in the Economic Optimum Reserve Margin ("EORM"), properly adjusted for risk. However, that risk-adjusted EORM must also meet a minimum reliability criteria threshold. Common practice in the industry regarding this threshold is to plan for a Loss of Load Expectation ("LOLE") of no greater than 0.1 days per year, which is more commonly referred to in the industry as a one event in ten years criterion ("1:10 LOLE").

As discussed earlier, the Company has historically relied upon a Target Reserve Margin only for the summer season. However, the 2015 Reserve Margin Study results shown in the 2016 IRP identified a significant increase in winter reliability risks due to several factors that had not previously been incorporated in the reserve margin determination. These included: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) increased occurrence of unit outages due to cold weather; (4)

greater penetration of solar resources; and (5) increased risk of fuel delivery disruption due to winter conditions. Along with these, the 2018 Reserve Margin Study identified a sixth factor—decreased supply alternatives from the wholesale power markets.

To address winter reliability issues, the Target Reserve Margin used in the 2016 IRP increased from 15 percent to 16.25 percent. Upon further consideration of the winter-related reliability risks, the Company will now use an independent evaluation of resource adequacy in both the summer and winter peak periods to ensure that System reliability is fully addressed. This results in the establishment of both a Summer Target Reserve Margin and a Winter Target Reserve Margin.

Defining Target Reserve Margins

The traditional formulation of the Summer Target Reserve Margin is stated in terms of weather-normal summer peak demands and summer capacity ratings according to the following formula:

$$STRM = \frac{TSC\text{-}SPL}{SPL} \times 100\%$$

Where:

STRM = Summer Target Reserve Margin;

TSC = Total Summer Capacity; and

SPL = Summer Peak Load.

The Winter Target Reserve Margin is similarly derived, but uses weather-normal winter peak demands and winter capacity ratings per the following formula:

$$WTRM = \frac{TWC - WPL}{WPL} \times 100\%$$

Where:

WTRM = Winter Target Reserve Margin;

TWC = Total Winter Capacity; and

WPL = Winter Peak Load.

Target Reserve Margins

After analyzing the load forecast and weather uncertainties, the cost of expected unserved energy, and the projected generation reliability of the System, the Company is maintaining the current 16.25 percent long-term Target Reserve Margin for the System as the Summer Target Reserve Margin to be applied to the summer peak planning season. To address the winter reliability concerns, the Company is adding a long-term Winter Target Reserve Margin of 26 percent for the System to be applied to the winter peak planning season. As explained in the 2018 Reserve Margin Study, the 26 percent long-term Winter Target Reserve Margin is consistent with the results of the 2015 Reserve Margin Study.

For the short-term, the Company is increasing the Summer Target Reserve Margin from 14.75 to 15.75 percent, with a commensurate short-term Winter Target Reserve Margin of 25.5 percent. The smaller gap between the long-term and short-term periods (regardless of season) is a direct consequence of changing load characteristics and energy efficiency programs that have reduced the overall peak demand response to economic uncertainty.

As noted earlier, one of the benefits of operating as part of the Southern Pool is that each Operating Company can carry fewer reserves than the System target. Thus, the diversified Summer Target Reserve Margin that applies to Alabama Power is 14.89 percent over the long-term and 14.39 percent over the short-term. Similarly, the Company's diversified Winter Target Reserve Margin is 25.25 percent over the long-term and 24.75 percent over the short-term. Changes in the load of each Operating Company relative to the loads of the others can impact this diversification effect.

Figure III-D-1 depicts the projected winter and summer reserve margins for Alabama Power through 2038, absent any resource additions. As the figure shows, the Company's winter reserve margin is projected to be below both its diversified long-term Winter Target Reserve Margin (25.25 percent) and its diversified short-term Winter Target Reserve Margin (24.75 percent) [redacted]. Figure III-D-2 provides the corresponding capacity amounts that would address Alabama Power's reliability deficits for the winter periods. Resolving the shortfalls in the winter periods with resources available year-round will also resolve the shortfalls occurring during corresponding summer periods shown on Figure III-D-3.

FIGURE III-D-1: Alabama Power Projected Seasonal Reserve Margins

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Winter	[redacted]									
Summer	[redacted]									

	2030	2031	2032	2033	2034	2035	2036	2037	2038
Winter	[redacted]								
Summer	[redacted]								

FIGURE III-D-2: Alabama Power Projected Winter Capacity Needs

Capacity Need (MW) - Winter		
Year	APC Reserve Margin (%)	APC Need (MW)
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]

FIGURE III-D-3: Alabama Power Projected Summer Capacity Needs

Capacity Need (MW) - Summer		
Year	APC Reserve Margin (%)	APC Need (MW)
2020	[redacted]	
2021	[redacted]	
2022	[redacted]	
2023	[redacted]	
2024	[redacted]	
2025	[redacted]	
2026	[redacted]	
2027	[redacted]	
2028	[redacted]	
2029	[redacted]	
2030	[redacted]	
2031	[redacted]	
2032	[redacted]	
2033	[redacted]	
2034	[redacted]	
2035	[redacted]	
2036	[redacted]	
2037	[redacted]	
2038	[redacted]	

While the Southern Pool affords the participants the ability to rely on temporary surplus capacity on the System, each Operating Company is expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations. Moreover, much of the available "surplus" in the Southern Pool is made up of fossil steam resources that are under significant cost pressures due to continued additional environmental compliance costs, coupled with forecasted low gas prices and modest load growth. The retail Operating Companies that own these units may decide at any point to retire some of the capacity on which Alabama Power might otherwise attempt to rely. Alternatively, those companies could make wholesale sales predicated on some or all of that capacity. In either case, the effect would be a reduction in the level of available capacity reserves on the System. Accordingly, Alabama Power must address its reserve deficiency, and intends to do so through appropriate action before the APSC.

III.E. Emerging Resiliency Needs

The Company remains committed to maintaining a robust and resilient electric system that is capable of reliably delivering electric energy, even in the face of unexpected events such as natural and man-initiated disruptions. The Company has a history of managing and planning for reliability risk through its reserve margin process, transmission planning analysis, and similar reliability studies, while also demonstrating substantial commitment to infrastructure protection initiatives. As the Company's generating fleet continues to transition away from resources with on-site fuel storage, there is increased fuel transportation risk associated with providing reliable electric service to customers. Additionally, the threat of low probability, high-impact events (such as physical- and cyber-attacks on electricity infrastructure) continues to grow.

At the bulk power system level, the Company routinely evaluates various contingencies as part of its transmission planning process and proposes projects to mitigate the risks associated with these contingencies. This level of planning meets or exceeds current North American Electric Reliability Corporation (NERC) standards. However, as the Company's generation resource mix continues to transition, continued transmission planning considerations must be given to these changing conditions to ensure future reliability and resilience of the bulk power system. The considerations could lead to the inclusion of other planning alternatives, such as a more expansive use of inactive reserve or the addition of fuel storage. Any actions, however, will be preceded by additional assessments of contingencies that may affect the IRP, such as the simultaneous failure of multiple elements of the electricity supply chain (e.g., transmission substations, gas pipelines, communication infrastructure, and generating stations). In many cases, this level of assessment is beyond current NERC planning standards. The Company remains committed to the reliable service of its customers, however, and will adapt as circumstances warrant.

III.F. Development of Indicative Resource Additions

In developing the benchmark plan, the Company begins with its existing resource portfolio, including its active DSM programs, along with its forecast of future customer needs.[8] For purposes of identifying future resource additions, the Company evaluates established and emerging resource

[8] An active DSM program is one that is dispatchable or controllable by the Company. In contrast, a passive DSM is an alternative adopted by customers that becomes embedded in their electric energy use patterns and requirements. The effects of passive DSM additions are captured in the load forecast in the form of peak load reduction megawatts.

options. The objective is to assess their cost, status of development, safety, operational reliability, flexibility, economic viability, fuel availability, construction lead times, and other factors.

The following is an overview of the screening process used to assess candidate technologies to determine those suitable for further screening for potential inclusion as indicative resource options in the expansion planning process.

- **Preliminary Screening:** The preliminary screening process identifies numerous technologies for strategic assessment. This strategic and qualitative assessment considers the maturity of the technology, construction lead times, operating characteristics, and financial requirements, along with cost uncertainties, environmental costs, safety of construction and operation, and resource availability. Many technologies from the initial list do not pass the preliminary screening due to their limited applicability to the territory (e.g., ocean thermal generation) or their early stage of development (e.g., magneto hydrodynamics).

- **Secondary Screening:** Technology options that pass the preliminary screening are then retained for a secondary screening. Generic candidate options are identified using qualitative factors such as scalability, repeatability, site requirements, and fuel availability. If a technology has potentially desirable characteristics, but only under unique circumstances (or not readily scalable and repeatable), then it will not pass the secondary screening and become a generic candidate or receive a Levelized Cost of Energy ("LCOE") analysis. Technologies that have desirable characteristics under unique application settings, such as specific customer requirements or geographic requirements, are retained separately to be evaluated for future projects should the right set of circumstances arise.

The identified generic candidates will undergo additional screening using a LCOE analysis. A LCOE analysis is a common industry method of using screening-level costs to provide an indication of the economic viability of one generating technology option when compared to others. LCOE models include both capital and operating costs relative to the energy produced. The results can then be used to perform a relative comparison of generating units with different operational profiles.

• **Expansion Planning Process:** Candidate technology options retained after the secondary screening become options for the expansion planning process. These options are further screened using a busbar analysis to identify economic options over a range of capacity factors.[9] Options selected at this stage are not, however, determinative of the resource or resources that will ultimately be procured. Rather they serve to indicate the type(s) of resource(s) (and the time needed for deployment) that may be required to meet an identified capacity need.

For the 2019 IRP, the above process yielded the following benchmark plan for Alabama Power. As reflected in Figure III-F-1, the plan calls for the addition of combined cycle and CT technologies totaling approximately 2,400 MW through 2028.

[9] *Intermittent resources, such as solar and wind, were not included as selectable technologies for the expansion planning model, but instead are evaluated pursuant to a separate analysis.*

FIGURE III-F-1: Alabama Power Winter Benchmark Plan

2019 IRP Winter Benchmark Base Case with Generic Additions						
Year	APC CT's	APC CC's	APC RM	APC NEEDS (MW)	ROC RM	ROC NEEDS (MW)
2020	-	-	[redacted]			
2021	-	-	[redacted]			
2022	-	-	[redacted]			
2023	300	-	[redacted]			
2024	-	-	[redacted]			
2025	-	900	[redacted]			
2026	-	-	[redacted]			
2027	600	-	[redacted]			
2028	300	270	[redacted]			
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					
2034	[redacted]					
2035	[redacted]					
2036	[redacted]					
2037	[redacted]					
2038	[redacted]					

The benchmark plan resulting from the 2019 IRP reflects the fact that the Company's electric demand (with necessary reserves) is materially higher than the Company's winter capacity resources, [redacted]

[redacted]

[redacted] Alabama Power cannot confidently rely on capacity reserves in the Southern Pool to address its reliability needs. As discussed earlier, there are two reasons for this conclusion. First, the Southern Pool affords the participants the ability to rely on temporary surplus capacity on the System, but each Operating Company is expected to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations. Consistent with this expectation, it is incumbent on Alabama Power to address significant and persistent shortfalls in its required level of capacity reserves needed to provide adequate reliability for its own customers. A second reason relates to the ongoing assurance of the available surplus in the Southern Pool. As stated earlier, much of that surplus capacity comprises fossil steam resources that are under challenging cost pressures for reasons including the ongoing cost of environmental compliance, forecasted low gas prices, and modest load growth. The retail Operating Companies that own these units may decide at any point to retire some of the capacity on which Alabama Power might otherwise attempt to rely. Alternatively, those companies are free to make wholesale sales predicated on some or all of that capacity. In either case, the effect would be a reduction in the level of available capacity reserves on the System.

Accordingly, Alabama Power has concluded that a modest acceleration of the resource additions indicated across the 2023 through 2028 time-frame will mitigate the described risks and better facilitate its statutory duty to make reasonable enlargements of its system to meet the demand of those customers for whom it holds a duty of service. Specifically, the Company intends to deploy additional resources by the winter of 2024 to address its Target Reserve Margin shortfalls for both the winter and summer seasons in a cost-effective manner. This plan already incorporates the effects of additional active and passive DSM resources across the planning horizon. The Company presently is working to identify the exact resources to respond to this need, including cost-effective demand-side opportunities. When the most appropriate resources are identified, the Company will file a petition for a certificate of convenience and necessity with the APSC requesting authorization to proceed with the resource additions.

IV. CONCLUSION

The 2019 IRP process has identified certain [redacted] capacity needs for Alabama Power. In particular, the Company's Winter Target Reserve Margin is well below its diversified winter target planning reserve margin guideline in the planning timeframe, signaling a significant need to add reserve capacity to address its winter reliability concerns. Consistent with its obligation to provide reliable service to its customers, the Company intends to pursue the necessary and appropriate measures to satisfy those needs. By doing so, Alabama Power will be in a position to continue meeting the demands of its customers in a reliable manner over the 20-year planning horizon, consistent with its statutory duty of service to its customers.

APPENDIX 1

Alabama Power Company Existing Supply-Side Resources

FIGURE A1-1: Alabama Power Company Existing Supply-Side Resources
(as of April 30, 2019)

Alabama Power Company Owned & Contracted Resource Summary					
	Plants	Units	Nameplate/ Contract Capacity (MW)	[redacted]	
Fossil	9	31	7,837		
Nuclear	1	2	1,720		
Hydro	14	41	1,668		
Solar	2	2	18		
Ownership Total	*26*	*76*	*11,243*		
Contracted Total	*N/A*	*N/A*	*1,546*		
Total Owned & Contracted			*12,788*		

Fossil Steam Plants					
Plant	Units	Nameplate Capacity (MW)	[redacted]	n-Service Year	Notes
Barry	1	125		1954	Barry 1 restored to active service in 2019
	2	125		1954	Barry 2 restored to active service in 2019
	4	350		1969	
	5	700		1971	
Gadsden	1	60		1949	
	2			1949	Gadsden 2 unavailable after Spring 2019
Gaston	1	125		1960	Ratings reflect 50% Alabama Power operating
					capacity; 100% owned by Southern Electric
					Generating Company (SEGCO)
	2	125		1960	Ratings reflect 50% Alabama Power operating
					capacity; 100% owned by Southern Electric
					Generating Company (SEGCO)
	3	125		1961	Ratings reflect 50% Alabama Power
					operating capacity; 100% owned by Southern
					Electric Generating Company (SEGCO)
	4	125		1962	Ratings reflect 50% Alabama Power operating
					capacity; 100% owned by Southern Electric
					Generating Company (SEGCO)
	5	880		1974	
Gorgas	8			1956	Gorgas 8 retired April 15, 2019
	9			1958	Gorgas 9 retired April 15, 2019
	10			1972	Gorgas 10 retired April 15, 2019
Greene County	1	150		1965	Ratings reflect Alabama Power 60% ownership
	2	150		1966	Ratings reflect Alabama Power 60% ownership
Miller	1	606		1978	Ratings reflect Alabama Power 91.8% ownership
	2	606		1985	Ratings reflect Alabama Power 91.8% ownership
	3	660		1989	
	4	660		1991	
Total	*16*	*5,572*			

Nuclear Steam Plants					
Plant	Units	Nameplate Capacity (MW)	[redacted]	n-Service Year	Notes
Farley	1	860		1975	
	2	860		1979	
Total	2	1,720			

Alabama Power Company Supply-Side Resource Summary - cont.

Gas-Fired Plants (Combustion Turbines)

Plant	Units	Nameplate Capacity (MW)	[redacted]	In-Service Year	Notes
Greene County	2	80		1996	
	3	80		1996	
	4	80		1995	
	5	80		1995	
	6	80		1995	
	7	80		1995	
	8	80		1996	
	9	80		1996	
	10	80		1996	
Total	*9*	*720*			

Gas-Fired Plants (Combined Cycles)

Plant	Units	Nameplate Capacity (MW)	[redacted]	In-Service Year	Notes
Barry	6	535		2000	
	7	535		2001	
Washington County	1	123		1999	Co-generation plant
Lowndes County	1	105		1999	Co-generation plant located at SABIC Innovative Plastics (formerly GE Plastics)
Theodore	1	236		2001	Co-generation plant
Total	*5*	*1,535*			

Oil-Fired Plants (Combustion Turbines)

Plant	Unit	Nameplate Capacity (MW)	[redacted]	n-Service Year	Notes
Gaston	A	10		1970	Ratings reflect 50% Alabama Power operating capacity; 100% owned by Southern Electric Generating Company (SEGCO)
Total	*1*	*10*			

Solar Powered Facilities

Plant	Unit	Nameplate Capacity (MW)	[redacted]	In-Service Year	Notes
Fort Rucker		10.6		2017	
Anniston Army Depot		7.4		2017	
Total	*2*	*18*			

Contracted Capacity

Plant		Nameplate Capacity (MW)	[redacted]	n-Service Year	Notes
Calhoun Power PPA		700		2003	
Westervelt PPA		8		2012	
Chisholm View PPA		202		2013	
Buffalo Dunes PPA		202		2014	
LaFayette PPA		72		2017	
Other		362			Represents net capacity that the Company has rights to through various contracts
Total		*1,546*			

Alabama Power Company Supply-Side Resource Summary - cont.

Hydro Electric Plants					
Plant	Units	Nameplate Capacity (MW)	[redacted]	In-Service Year	Notes
Weiss	1	29.25		1962	Upper Coosa Group
	2	29.25		1961	Upper Coosa Group
	3	29.25		1961	Upper Coosa Group
Henry	1	24.3		1966	Upper Coosa Group
	2	24.3		1966	Upper Coosa Group
	3	24.3		1966	Upper Coosa Group
Logan Martin	1	45		1964	Upper Coosa Group
	2	45		1964	Upper Coosa Group
	3	45		1964	Upper Coosa Group
Lay	1	29.5		1968	Lower Coosa Group
	2	29.5		1968	Lower Coosa Group
	3	29.5		1967	Lower Coosa Group
	4	29.5		1967	Lower Coosa Group
	5	29.5		1967	Lower Coosa Group
	6	29.5		1967	Lower Coosa Group
Mitchell	4	20		1949	Lower Coosa Group
	5	50		1985	Lower Coosa Group
	6	50		1985	Lower Coosa Group
	7	50		1985	Lower Coosa Group
Jordan	1	25		1928	Lower Coosa Group
	2	25		1928	Lower Coosa Group
	3	25		1928	Lower Coosa Group
	4	25		1928	Lower Coosa Group
Bouldin	1	75		1967	Lower Coosa Group
	2	75		1967	Lower Coosa Group
	3	75		1967	Lower Coosa Group
Martin	1	46		1926	Tallapoosa Group
	2	41		1926	Tallapoosa Group
	3	40		1926	Tallapoosa Group
	4	55		1952	Tallapoosa Group
Thurlow	1	34.02		1930	Tallapoosa Group
	2	34.02		1930	Tallapoosa Group
	3	12.96		1930	Tallapoosa Group
Yates	1	23.5		1928	Tallapoosa Group
	2	23.5		1928	Tallapoosa Group
Harris	1	66		1983	Tallapoosa Group
	2	66		1983	Tallapoosa Group
Smith	1	78.75		1961	Warrior Group
	2	78.75		1962	Warrior Group
Bankhead	1	53.985		1963	Warrior Group
Holt	1	46.944		1968	Warrior Group
Total	*41*	*1,668*			

APPENDIX 2

Alabama Power Company
Demand-Side Management Programs

Alabama Power is committed to both economic growth and environmental stewardship within the state. In concert with customer needs and desires, Alabama Power works to ensure that it continues to have the reliable and cost-effective energy needed to promote the interests of the region. In doing so, Alabama Power continues to be an industry leader in cost-effective DSM programs. The Company implements DSM measures and programs that are designed to reduce customers' energy bills, improve their competitiveness, assist with system load shape management (thereby reducing costs and the need for future capital investment), and help customers use energy as efficiently as possible. All customer segments (industrial, commercial, and residential) are potential participants in these programs.

Changes in technology and other influencing factors can, along with education, provide opportunities for the Company to work more with customers to help them manage and control their energy use, making it more efficient and economical. In managing its DSM programs, Alabama Power must be mindful of the effect they can have on electricity prices. Accordingly, the Company pursues those programs that are expected to benefit all of its customers, thereby avoiding the situation where some customers are effectively being caused to subsidize the benefits realized by others.

The economic health of all customers is not only important to Alabama Power, but also to the state and its future economic vitality. Therefore, future DSM programs can be expected to continue to balance these considerations in a cost-effective manner – encouraging customers' wise and efficient use of energy, while maintaining an economically vibrant and productive region.

Alabama Power currently has customers participating in more than 15 DSM programs in the residential, commercial, and industrial sectors, as well as programs managed through the Company's Distribution Operations. The 2019 IRP includes approximately 1,511 MW of existing contracted active demand-side programs that have allowed the deferral of 1,219 MW of supply-side resource capacity in the winter. The difference between the nominal values shown for the demand-side programs and the associated supply-side resource capacity deferrals is due to the lower availability of capacity equivalence under DSM program, as compared to a supply-side resource. As noted earlier, DSM programs that are subject to the direct control of the Company (e.g., non-residential interruptible load) are called "active DSM." The DSM programs dependent on customer behavior or energy usage patterns (e.g., equipment SEER efficiency increases, insulation/infiltration upgrades) are called "passive DSM." The passive DSM programs serve to reduce expected peak load and consequently are embedded in the Company's load forecast. Existing passive DSM programs are estimated to have resulted in a winter peak load reduction of 363 MW. Therefore, the total amount of existing DSM programs reflected in the 2019 IRP is 1,511 MW plus 363 MW, for a total of 1,874 MW.

Active DSM Programs

The capacity values associated with the Company's active DSM programs, as reflected in the 2019 IRP, are shown in Figure A2-1 Winter and Figure A2-1 Summer, followed by a description of those programs.

FIGURE A2-1 Winter

INTEGRATED RESOURCE PLAN - 2019

Projections of Active Demand-Side Options (DSOs) 2019-2038

Active DSOs

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Contract Amounts	[redacted]									
Resource Deferral Amounts										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Contract Amounts	[redacted]									
Resource Deferral Amounts										

Active DSOs - Contract Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Contract Amount										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Contract Amount										

Active DSOs - Resource Deferral Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Resource Deferral Amount										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Resource Deferral Amount										

Active Demand-Side Options are those activated, i.e., dispatchable or controllable, by the Company at the time of need.
Active DSOs are explicitly indicated in the Integrated Resource Plan (IRP) as a resource. Active DSOs reflected here are inputs for the 2019 IRP.

FIGURE A2-1 Summer

INTEGRATED RESOURCE PLAN - 2019

Projections of Active Demand-Side Options (DSOs) 2019-2038

Active DSOs

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Contract Amounts	[redacted]									
Resource Deferral Amounts										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Contract Amounts	[redacted]									
Resource Deferral Amounts										

Active DSOs - Contract Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Contract Amount										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Contract Amount										

Active DSOs - Resource Deferral Amounts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
\Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Resource Deferral Amount										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Rate Real Time Pricing (RTP)	[redacted]									
150 & 200 Hour Interruptible										
600 Hour Interruptible										
Non-Indust. Direct Load Control										
Customer Standby Generation										
Distribution Regulation Option Program (DROP)										
Total Active DSO - Resource Deferral Amount										

Active Demand-Side Options are those activated, i.e., dispatchable or controllable, by the Company at the time of need.
Active DSOs are explicitly indicated in the Integrated Resource Plan (IRP) as a resource. Active DSOs reflected here are inputs for the 2019 IRP.

DESCRIPTION OF ACTIVE DSM PROGRAMS

Residential Demand Response Programs:

1. Centsable Switch – A cycling program whereby a customer's HVAC is cycled 67 percent during the months of June through September up to 5 hours per day, subject to a maximum of 150 hours per year.

2. SmartPower Critical Peak Pricing Program – Participating customers receive service under a time-of-use rate with a critical peak price ("CPP") component, and are incented to manage their load during critical peak periods through the issuance of price signals from the Company.

Commercial and Industrial Demand Response Programs:

1. Industrial Interruptible Program – This program, which is currently one of the largest of its kind in the nation, allows Alabama Power to call for the interruption of load with 15 to 30 minutes' notice. The Company's right to interrupt is subject to contractual limitations (e.g., no more than 200 to 600 hours per year and no longer than 8 hours per call).

2. Real Time Pricing – Industrial pricing option based on marginal costs plus applicable adders to recover fixed costs.

3. Standby Generator Program – Under this program, customers enter into a contract with Alabama Power to switch to their standby generators with no notice for use in non-emergency circumstances. The Company is limited to calling these contracts for not more than 200 hours a year (not including maintenance and testing), with no call exceeding 8 hours.

4. Supplemental Reserves – Less than 15-minute interruptible load that can be called as needed to support system operations.

Transmission and Distribution Energy Efficiency Programs:

1. Distribution Regulation Optimization Program ("DROP") – A conservation voltage control option that lowers the voltage on distribution feeders to lower the demand and reduce Volt Ampere Reactive ("VAR") requirements on the system. The target activation periods under this program are the summer and winter peaks.

Active DSM Pilot Programs – The Company is currently conducting the following pilot programs with small test groups within the residential class to assess the potential for active DSM in the winter.

1. Power Pause – The Power Pause pilot officially started on June 1, 2019. The premise behind the pilot is the development of a residential interruptible program that can be utilized not only for summer months, but also for winter and shoulder months. The current program is limited to employees taking service from the Company and only applies to customers with a 200-amp service. Beginning in 2020, a 400-amp meter should be available and will allow the Company to extend the pilot to additional participants. The pilot allows the Company, using remote connect/disconnect ("RCDC") meters, to interrupt electric service to participants subject to the following parameters:

- Months Available – January to December
- Total Annual Interruptible Hours – 40 Hours
- Maximum number of Hours per Event – 4 Hours
- Maximum events in a day – 2 Events
- Available Time Periods – Monday – Friday (24 Hours per Day)
- Excluded Time Periods – Holidays and Weekends.

2. Residential Water Heater Pilot – The Residential Water Heater pilot is expected to start later this year (2019). The goal of the pilot is to study electric water heating usage patterns of the Company's customers and then accommodate those patterns in a way that reduces overall electrical demand without adversely impacting the availability of hot water for those customers. Based on the participant's hot water usage pattern, the participant will be placed in a specified group. The Company will then manage the water heater demand of the various groups using switches that control the electric elements and temperature, providing an opportunity for peak load shaving throughout the year.

Passive DSM Programs

The projected load reductions associated with the Company's passive DSM programs, as embedded in the load forecasts underlying the 2019 IRP, are shown in Figure A2–2 Winter and Figure A2–2 Summer, followed by a description of those programs.

FIGURE A2-2 Winter

INTEGRATED RESOURCE PLAN - 2019

Projections of Passive Demand-Side Options (DSOs) 2019-2038

Gross Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Winter	[redacted]									
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
PEAK (MW) Winter	[redacted]									

Passive DSO Impacts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential Energy Efficiency Programs	[redacted]									
Commercial Energy Efficiency Programs										
Industrial Energy Efficiency Programs										
Peak (MW) Winter										
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Residential Energy Efficiency Programs	[redacted]									
Commercial Energy Efficiency Programs										
Industrial Energy Efficiency Programs										
Peak (MW) Winter										

Net Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Winter	[redacted]									
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
PEAK (MW) Winter	[redacted]									

Passive DSOs are those alternatives adopted by customers that become inherent in their electric energy use pattern and requirements. Passive DSOs are embedded in the Company's load forecast and enumerated in the Integrated Resource Plan.

FIGURE A2-2 Summer

INTEGRATED RESOURCE PLAN - 2019

Projections of Passive Demand-Side Options (DSOs) 2019-2038

Gross Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Summer	[redacted]									

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PEAK (MW) Summer	[redacted]									

Passive DSO Impacts

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential Energy Efficiency Programs	[redacted]									
Commercial Energy Efficiency Programs										
Industrial Energy Efficiency Programs										
Peak (MW) Summer										

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Residential Energy Efficiency Programs	[redacted]									
Commercial Energy Efficiency Programs										
Industrial Energy Efficiency Programs										
Peak (MW) Summer										

Net Peak Load

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PEAK (MW) Summer	[redacted]									

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PEAK (MW) Summer	[redacted]									

Passive DSOs are those alternatives adopted by customers that become inherent in their electric energy use pattern and requirements. Passive DSOs are embedded in the Company's load forecast and enumerated in the Integrated Resource Plan.

Residential Energy Efficiency Programs:

1. Smart Neighborhood Builder Program – This program promotes the installation of heat pumps and electric water heaters in new homes that are constructed to meet a Home Energy Rating System ("HERS") Index of 65 or below. A typical home built to the 2006 International Energy Conservation Code ("IECC") would be given a HERS rating of 100. Each point of reduction in the HERS index represents a one percent increase in energy efficiency. Therefore, a Smart Neighborhood home is at least 35% more efficient than a typical home built to the 2006 IECC. Additionally, Smart Neighborhood homes feature smart home devices, such as smart thermostats and smart light switches, which allow homeowners to monitor and control their energy usage from their mobile device.

2. Heat Pump Water Heater Program – This program promotes the installation of heat pump water heaters which uses energy efficient heat pump technology to transfer heat from the surrounding environment to the water.

3. Tankless Water Heater Program – This program promotes the installation of electric tankless water heaters in new construction. Electric tankless water heaters heat water when it is needed instead of holding the water in a tank.

4. Residential Time Advantage Rates – Time Advantage Rates provide pricing signals by time period to incent customers to shift their usage to lower cost periods.

5. Residential Plug-in Electric Vehicle Rate Rider – The rider offers a daily 1.7155 cent/kWh discount on the customer's whole house electric usage between the hours of 9pm and 5am to incent the customer to charge their electric vehicle(s) during off-peak hours.

Residential Customer Value Programs:

1. In-Home Energy Check-Up – This program provides for in-home energy audits performed by Alabama Power Energy Sales and Efficiency personnel.

2. Online Energy Check-Up – This program makes an on-line energy audit available to all residential customers.

Commercial Energy Efficiency Programs:

1. Energy Star Cooking – This program promotes Energy Star cooking equipment in the commercial market.

2. Heat Pump Water Heater Program –This program promotes heat pump water heaters in the commercial market.

3. Business Time Advantage Rates – Time Advantage Rates provide pricing signals by time period to incent customers to shift their usage to lower cost periods.

Commercial and Industrial Customer Value Programs:

1. In-Business Energy Check-Up (Commercial) – This program makes available an in-business energy audit performed by Alabama Power Energy Sales and Efficiency personnel.

2. Smart Energy Use Program (Industrial) – This program provides customers with an evaluation of their manner (equipment type or technology application) and practices of energy consumption.

Transmission and Distribution Energy Efficiency Programs:

1. Distribution Energy Efficiency Program ("DEEP") – DEEP operates continuously using capacitors to reduce voltage drop on distribution feeders. The lower voltage upstream of distribution feeders lowers the demand and reduces VAR requirements on the system.

Alabama Power's overarching goal as an electric supplier is to maintain high reliability at cost-effective rates, while providing exceptional customer service. With respect to energy efficiency, the Company supports reasonable building codes and appliance standards that result in customers becoming more efficient in their use of electricity. Alabama Power also works with its customers to help them learn ways to better manage their energy usage and thereby become more efficient users. As part of these efforts, the Company's energy efficiency programs are reasonably expected to benefit all customers, enabling them to realize lower rates than would have been the case had other alternatives been pursued (either supply side or demand side).

APPENDIX 3

Alabama Power Company
Procurement of
Renewable Resources

Consistent with the 2013 and 2016 IRPs, the Company continues to explore adding to its generation mix renewable resources that are projected to bring benefits to customers. This strategy is evidenced by the Company's procurement and development of over 500 MW of renewable energy since 2011. Under these projects, the Company has rights to the environmental attributes, including the renewable energy certificates ("RECs"), associated with the energy. Alabama Power can retire some, or all, of these environmental attributes on behalf of its retail electric customers or it can sell the environmental attributes, either bundled with energy or separately, to third parties.

The Company's renewable resource strategy also reflects action taken by the APSC. On September 16, 2015, the Commission issued to the Company a certificate of convenience and necessity in Docket No. 32382 authorizing the development or procurement of up to 500 MW of capacity and energy from renewable energy and environmentally-specialized generating resources. Projects presented to the Commission for approval pursuant to the certificate must satisfy certain eligibility criteria. First, the project must involve a renewable energy resource (such as those identified in Alabama Code § 40-18-1(30)) or an environmentally specialized generating resource (such as combined heat and power) and be no larger than 80 MW (measured in alternating current ("AC") terms). Second, the project must meet certain economic benefits criteria, namely, that it is expected to result in a positive economic benefit for all of Alabama Power's customers. The APSC will consider projects up to 160 MW of the certificated amount annually; any proposal in excess of that annual threshold requires prior authorization. In addition, any unexercised authority under the certificate expires after six years.

Consistent with the certificate authority in Docket No. 32382, the APSC subsequently approved two projects on December 14, 2015. Specifically, on December 14, 2015, the APSC authorized Alabama Power to construct and own two solar facilities at army installations served by the Company, which were placed into commercial operation in 2017. Fort Rucker was placed into service on April 1, 2017 at 10.6 MW and Anniston Army Depot ("ANAD") was placed into service on July 14, 2017 at 7.4 MW. Additionally, on June 9, 2016, the APSC approved a power purchase agreement ("PPA") for the output of a solar facility near the town of LaFayette in Chambers County, which went into commercial operation on December 15, 2017 at 72 MW. These solar projects are reflected in this 2019 IRP. Alabama Power is receiving all energy and associated RECs generated by these projects, which it uses to serve its customers with solar energy and also sells portions to third parties for the benefit of customers.

Also, pursuant to the certificate authority in Docket No. 32382, the Company will continue to consider and evaluate other projects that would satisfy the criteria set forth in the Commission's certificate order through biannual Renewable Requests for Proposals ("RFPs"). Qualifying proposals submitted through these RFPs will afford Alabama Power an opportunity to review market offerings and determine whether there are economic and viable energy projects suitable for pursuit consistent with the requirements of the order.

The Company will continue to consider and evaluate projects that resulted from the 2016 or 2018 RFPs and unsolicited bids for projects that would satisfy the criteria set forth in the Commission's certificate order. Additional renewable resources will be added to its plan as they are identified, either through the exercise of the authority under that certificate or through another vehicle.

PUBLIC VERSION

Alabama Power

Direct Testimony of John B. Kelley

Exhibit JBK-2

Alabama Power Company

2018

CAPACITY REQUEST FOR PROPOSALS

Issued: September 21, 2018

Forecasting and Resource Planning
Alabama Power Company
600 North 18th Street
Birmingham, AL 35203

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Introduction

Alabama Power Company ("Company") hereby announces the 2018 Request for Proposals ("RFP") for resources of a capacity rating between one hundred megawatts (100 MW) and twelve hundred megawatts (1,200 MW). Qualifying proposals submitted through this RFP will afford Alabama Power Company an opportunity to review market offerings to determine whether there are economic and viable energy projects suitable to provide reliable, dispatchable, cost-effective capacity and energy resources to meet the needs of its customers. The Company is seeking capacity that is available to commence service in the 2019-2023 timeframe, with the amount depending upon the cost competitiveness of the respective offers as well as options available to the Company. The Company is interested in proposals for:

(A) Power purchase agreements ("PPAs") from electric generation facilities; and

(B) Asset purchase and sale agreements ("APSAs") for both: (i) existing generation facilities; and (ii) new-build/transfer electric generation facilities (*i.e.*, new facilities to be constructed that will be acquired after substantial completion through a purchase transaction).

All proposals must be for resources that, at a minimum, meet established reliability and performance criteria and that can be dispatched on demand (with appropriate notification) by the Company. Each project proposed must be at least one hundred megawatts (100 MW) in size and no single resource should exceed twelve hundred megawatts (1,200 MW). Proposals may encompass any type of energy source. The Company is seeking proposals from projects that will be available and dispatchable to meet capacity needs for both its summer (June – September) and winter (December – February) peak demands. This RFP is not open to any affiliate of the Company, including but not limited to Southern Power Company.

Nothing in this RFP or in the associated materials provided should be considered an offer or acceptance of terms or conditions of a PPA, an APSA, an interconnection agreement, or any other contract or business arrangement. Any proposal that does not satisfy the requirements of this RFP may be considered nonresponsive, and the Company reserves the right to reject any such proposal without opportunity for correction or cure. The Company may, but is under no obligation to, contact any bidder to obtain additional information regarding its proposal. Each participating bidder waives any and all right of recourse against the Company, its parent, and any of their affiliates or subsidiaries (including their officers, directors, employees, agents and representatives for either rejection of the proposal or for failure to execute an agreement with the bidder for any reason. The Company shall have no obligation or liability to any bidder unless and until a definitive agreement with such bidder has been successfully negotiated, fully executed, and any and all conditions precedent and subsequent to the effectiveness of such agreement are satisfied. The Company reserves the right, in its sole discretion, to determine whether to pursue negotiation and execution of any agreement with any bidder. Further, any agreement shall be subject to all requisite management approvals of the Company as well as approval by the Alabama Public Service Commission ("APSC") in a form suitable to the Company, in its sole discretion. Proposals submitted pursuant to this RFP will be evaluated in a manner deemed appropriate by the Company, including but not limited to evaluations that measure proposals against one another on a like-kind basis (independent of technology type) and against other power supply options that may be available to the Company. Such other power supply options may include generation resources owned or developed by the Company, other generation resources located in the service territories of the Company and its affiliates, and other proposals for firm capacity generation that are provided to the Company outside of this RFP process. The Company is under no obligation to select any project, nor is the Company limited to choosing from the proposals submitted in response to this RFP. The Company may determine in its sole discretion to exclusively procure firm capacity resources outside of this RFP process, or to defer the pursuit of any resources, through proposals identified in this RFP or otherwise, until a future date determined by the Company.

Confidentiality

Participation in this RFP is conditioned on the execution of a standard Confidentiality Agreement, a copy of which is being provided for each bid type proposal being solicited in Attachment B: Notice of Intent to Bid ("NOI") Forms.

The Company will take reasonable precautions and use reasonable efforts to protect any proprietary and/or confidential information contained in a bid proposal provided that the bidder clearly identifies such information as confidential on the page on which it appears. The Company may, however, be required to make such confidential information available under applicable state and/or federal law to regulatory commission(s), their respective staff or other governmental agencies having jurisdiction. In addition, the Company reserves the right to release such information to agents or contractors of the Company, for the purpose of market resource assessment and evaluation of bid proposals, or to regulated retail affiliates seeking similar supply-side resources. The Company further reserves the right to share generating facility specific information with a new facility owner if the seller assigns or otherwise transfers control of the facility to a new owner. Under no circumstances will the Company, its parent company, affiliates, subsidiaries, and the officers, directors, employees, agents or representatives of any of them be liable to any party for any damages resulting from any disclosure of information provided in response to this RFP before, during or after the solicitation process. In the event the winning bidder elects to sell the generating facility that is the subject of the proposal, the Company may share the winning bidder's confidential information (*i.e.*, information on operations, reliability, etc.) with prospective buyers who are identified by seller, to ensure future performance in accordance with the applicable agreement

Communications

Prior to the Submission of Bids

All questions to the Company regarding the RFP should be submitted utilizing the "Contact Us" link on the RFP website, www.alabamapower.com/our-company/how-we-operate/capacity-rfp.html. Properly submitted questions along with the appropriate responses will be recorded in a bidders question and answer form and periodically sent to bidders from the Company via email from G2APCRPRFP@southernco.com. Other than questions and answers submitted using the "Contact Us" link on the RFP website, no other explanations or interpretations of this RFP will be given. Questions will be accepted by the Company until five (5) business days (November 2, 2018) before the date on which bid proposals are due.

The RFP document and its Attachments A-H will be made available on the RFP website. All bidders must submit the required Notice of Intent to Bid ("NOI") forms by October 5, 2018 by 5:00 p.m. CDT. Bidders failing to submit an NOI by this time date may have their proposals summarily rejected by the Company, in its sole discretion. The Company will allow bidders to list up to a maximum of three individuals as contacts during the RFP process. The contact information for these individuals must be included in the required NOI form "Contact(s) for RFP Process" in Attachment B.

All bidders should familiarize themselves with this RFP document and all its attachments, located on the RFP website (www.alabamapower.com/our-company/how-we-operate/capacity-rfp.html). Interested parties are expected to be able to download this RFP with its required attachments, complete the attachment forms and submit the attachment forms via email to G2APCRPRFP@southernco.com and one hardcopy via mail by the RFP deadline of November 9, 2018 by 5:00 pm CST to the Company. All bidders should refer to this RFP document for guidance in the event there are any differing of references between this RFP document and its attachments.

Emailed files **CANNOT** be received as a .ZIP file, be greater than 20MB in size, or posted in a file sharing folder (e.g., DropBox®[1] or Google Docs™[2]).

Any and all communications regarding this RFP should be submitted through the above-referenced process. Attempts at direct communications with the Company or Southern Company Services regarding the RFP will be disregarded.

Following the Submission of Bids

All communications with bidders following the submission of bids shall be conducted through the Company and shall be confidential. Such communications may include one or more face-to-face meetings with each bidder, attended by the Company and other Company

[1] DropBox is a U.S. registered trademark for DropBox, Inc
[2] Google Docs is a trademark of Google LLC

representatives and advisors, in order to discuss the bidder's proposal(s). In addition to or in lieu of face-to-face meetings, the Company and other Company representatives or advisors also may conduct telephonic conference calls with a bidder in order to clarify bid proposals or resolve issues with such bid proposals.

Following the Execution of the Final Contract

Winning bidders may not announce the execution of any final PPA or APSA via a press release or any other method of public communication without prior approval of the Company.

Operational Parameters and Requirements

The Company is seeking RFP resources that can meet the operational requirements and parameters described in this section in order to meet the Company's reliability needs in both the winter and summer. All bid proposals should provide all pertinent operational information and should identify any inability to meet one or more criteria set forth in the "Operating Parameters" tab of Attachment C: RFP Bid Forms.

Minimum and Maximum Capacity Limits of Resources

Each project proposal, including an aggregate of units at a facility, must be at least one hundred megawatts (100 MW) in total capacity for the resource proposed, and no single resource should exceed twelve hundred megawatts (1,200 MW).

Seasonal Availability and Capability

All bid proposal projects must provide the capacity ratings of the facility for the summer (June-September) and winter (December-February) seasons. For the winter season, the capacity ratings can be in the form of a separate winter season capacity rating, guaranteed output at various low temperatures, or a guarantee of "as capable" output with an associated temperature-output engineering curve. For PPAs, the resources must be available year-round, and not be subject to scheduled outages in either the winter or summer seasons.

AGC Requirements

All proposals must be sourced from generating facilities capable of operating on Automatic Generation Control ("AGC"). Seller shall be responsible for all costs to make the unit capable to respond to the Company's AGC signals. For PPAs, the Company shall have the right, but not the obligation, to dispatch the facility in the AGC mode. For PPA proposals involving facilities that are not connected to the Southern Company transmission system, bidders should verify dynamic transfer capability and protocols with the Southern Company transmission system to ensure proper telemetry communications per the Southern Company Open Access Transmission Tariff ("OATT").

Run Time Requirements

Combined cycle ("CC") resources must have a minimum down time of no more than 8 hours, and combustion turbine ("CT") resources must have a minimum down time of no more than 4 hours (although a minimum down time of no more than 1 hour is preferred).

Quick Start Capability (for CTs)

For proposals reflecting CT resources, the Company requires quick start capability (i.e., 10 minutes or less following notification from the Company operations personnel).

Demineralization/Environmental

The use of demineralized water supply for a resource should not limit the operations or delivery of capacity and should be able to at least support 24 hours of full load generation plus 10 hours of full pressure generation (if applicable).

Fuel Plan

Fuel Evaluation for Proposals

Natural Gas prices will be linked to a single monthly forecast of gas prices at a common point (Henry Hub). Delivered gas prices will include the effect of applicable gas transportation charges, fuel retention rates, historical basis differentials and taxes. The requirement to purchase firm gas transportation and storage will be applied as follows for evaluation purposes.

- CC units will be evaluated with sufficient firm gas transportation to allow 24 hours of operation at full load and 10 hours operation at peaking or secondary modes of operation. CC units will also be evaluated with 13 days of gas storage capacity based on firm gas transportation capacity. Some reduction in gas storage capacity may be given to CC units with fuel oil storage; however, fuel oil inventory costs will be applied.

- Simple cycle units without sufficient oil backup will require eight (8) hours of firm gas transportation year-round. Simple cycle units with sufficient oil backup will not require firm gas transportation provided it can burn oil year-round. Simple cycle units with sufficient oil backup that cannot burn oil in the summer months will require eight (8) hours of firm gas transportation during the summer months. Gas storage is not required for simple cycle units, but fuel oil backup is strongly encouraged. Fuel oil inventory costs will be applied as appropriate.

Fuel Oil Evaluation for Proposals

The Company prefers fuel oil availability for both CC and CT proposals. The supporting facilities (including infrastructure and property interests) and operation for onsite fuel oil storage will be expected to comply with the following standards, including both tolling and non-tolling proposals for PPAs:

- For CC facilities, sufficient fuel oil storage capacity and reliable replenishment capability to operate the generating facility for five (5) continuous days per week for two (2) consecutive weeks at sixteen (16) hours per day at full load.

- For CT facilities, sufficient fuel oil storage capacity and reliable replenishment capability to operate the generating facility for five (5) continuous days per week for two (2) consecutive weeks at eight (8) hours per day at full load.

- If a bidder cannot meet the storage and replenishment capabilities outlined above, the bidder should indicate its storage and replenishment capabilities and the Company will evaluate this as a qualitative, non-price factor. For PPA proposals, the parties will develop the additional requirements and objectives necessary to implement the foregoing standards as a part of the PPA.

Power Purchase Agreement Proposals

For purposes of this RFP, the Company is interested in PPA bid proposals based upon "tolling" principles for five (5), ten (10), fifteen (15) and twenty (20) year terms from a dedicated (first-call) generating resource (the "Facility"). The only PPA product that will be acceptable is a 100% capacity and energy entitlement from one or more dedicated generating units. Capacity offered under a PPA proposal will have the most value if fully dispatchable and available year-round for first-call twenty-four (24) hours per day and seven (7) days per week for the contracted period. PPA bid proposal prices must include all costs that the bidder expects the Company to pay for the capacity and energy proposed, including any ancillary services, such as reactive power, frequency response, etc. The Company will not be responsible for any other costs associated with the project, including but not limited to, station service, test energy, fuel for testing, rail spur construction, fuel handling facilities, transmission system interconnection and all costs incurred necessary to accomplish synchronization. On-site fuel storage or dual-fuel capability is not required, but the non-price factor contribution of such characteristics will be considered. For proposals offering multiple units in a single bid proposal, the bidder should indicate whether each unit may be selected separately by the Company at the $/kW bid capacity price and with the other pricing components proposed for the entire bid. If a bidder desires to not offer such unit combinations, the bidder should clearly state so in the bid proposal. If the bidder desires to offer a different pricing structure for such unit combinations, the bidder must specifically identify this pricing in its proposal.

Delivery of Energy

At all times during the PPA term, the delivery point must be at an available interface into or within the Southern Company transmission system and capable of being designated as a firm network resource as defined under the OATT. For each project, the Company will determine the facilities and upgrades (and associated costs) needed beyond the point of delivery. Such costs will be considered in the Company's evaluation. In addition to evaluating facilities and upgrades required for interconnection, an important consideration in the evaluation of proposals will be whether there is adequate transmission to deliver the energy of a proposed project from the proposed point of interconnection to the Company and its customers on a reliable basis. The costs of any modifications to the transmission system to reliably deliver energy to the Company and its customers will be taken into account in the evaluation. The Company will not be responsible for any delivery charges or any costs (*e.g.*, congestion) at or before the point of delivery.

Delivery of energy to meet the Company's schedules must be from the Facility identified in a bidder's PPA proposal in response to this RFP. If a bidder expects its Facility will not be available per the Company specified deadline, the bidder may propose an interim resource, which can be in the form of a physical unit provided that the physical interim resource is clearly identified and committed. The Company will only allow interim resources with a megawatt capacity that is within the range of ten percent (10%) or less to five percent (5%) more than the megawatt capacity of the primary Facility; provided, however, that the period of time a bidder uses an interim resource to fulfill such capacity need may not exceed one (1) year for a five (5) year or ten (10) year PPA term and two (2) years for a fifteen (15) year or twenty (20) year PPA term. In the case of a multiple resource proposal, there must be no change proposed in the amount of capacity offered over the term of the PPA beyond that described above, and all requirements of this RFP shall apply equally to both the primary and interim resources. Also, appropriate adjustments to the Pro Forma PPA will be made (*e.g.*, the date when permits must be obtained for the primary Facility).

Firmness of Proposed Resources

To be considered responsive, PPA proposals, including interim PPA resources, bidders are required to provide the proposed capacity and energy to the Company from specific, dedicated generating unit(s) on an unencumbered first-call basis and priority. In the event a resource is not directly connected to the Southern Company transmission system at any time during the term of the PPA, the bidder must secure firm transmission service from the source to the Southern Company transmission system, with roll-over rights.

In the event a bidder intends to supply the capacity offered in its bid proposal through purchase(s) from a third party, such bid proposal must demonstrate that the generation source for the bidder's purchase(s) will provide the Company with the same unencumbered first-call firmness discussed above as if the bidder owned such generating resources. In addition, appropriate provisions will be added to the Pro Forma PPA to ensure adequate protection of the Company.

Interconnection and Transmission Requirements (Projects connected to the Southern Company Transmission System)

1. The costs and benefits of any network transmission system modifications to the Southern Company transmission system that are required to reliably incorporate the proposed resource into the transmission grid will be considered in the evaluation. Southern Company Services, Inc., acting as agent for the Company, will conduct transmission impact studies, as appropriate, to determine an estimate of such costs and benefits for inclusion in the bid evaluation.

2. Each PPA bidder should propose the discrete point of electrical interconnection for its project, which will define the point where the generator interconnection facilities connect to the existing transmission system. In proposing the point of interconnection, the bidder will bear cost responsibility for all generation and transmission interconnection facilities from the bidder's generating equipment to the proposed point of interconnection.
    a. The proposed point of electrical interconnection should be consistent with the expected point of electrical interconnection that would be established if the bidder was currently applying for formal interconnection.

    b. If the bidder's Facility has an interconnection agreement in place or has applied for a formal interconnection, the bidder should provide a copy of the interconnection agreement or application and, in the case of an application, a summary of the status (*e.g.*, interconnection granted, pending).

    c. Each bidder must supply a one-line diagram of the electrical system depicting the Facility's generator(s), generator step-up transformer(s), collector bus(ses), high voltage circuit breaker(s) and connections to the transmission system. In addition, each bidder must clearly mark the proposed point of interconnection on such one-line diagram and clearly indicate the line of demarcation (*i.e.* the change of ownership) between the Facility and the transmission provider's facilities.

d. The Company may suggest a different point of interconnection point (with respect to location and/or voltage) if this would result in more favorable economic consideration of the bid proposal being evaluated, or as may be required per Company interconnection policy and business practices.

3. For the purpose of this RFP, PPA bidders shall be responsible for all transmission interconnection costs from the generating equipment to the bidder's proposed point of interconnection in their bid proposal, as described in paragraph 2 above. Successful bidders are responsible for all costs they incur related to interconnection of their Facility to the Southern Company transmission system in accordance with their interconnection agreement. In addition, successful bidders will be responsible for any costs for upgrades required to electric systems other than the Company's transmission system as a result of interconnection Affected System (as defined in the OATT) improvements.

4. Successful PPA bidders will be required to have submitted a valid interconnection request for study within one week of short list notification. It is each bidder's responsibility to contact the appropriate transmission provider to obtain all relevant information regarding interconnection requirements for their Facility.

5. Successful PPA bidders must demonstrate that they can reliably deliver energy to the bidder's proposed point of interconnection. The Company will accept no risk of failure to so deliver.

6. The Company is seeking proposals for which firm network integration transmission can be available to serve the Company's loads by the commencement and throughout the term of the PPA. The Company will determine whether network integration capability exists and the likely cost to maintain such status over the term of the PPA. Bidders may desire to obtain additional information regarding the Southern Company transmission system and capabilities by using Southern Company's Open Access Same Time Information System ("OASIS") web site (located at https://www.oasis.oati.com/SOCO).

Transmission Requirements (Projects not connected to the Southern Company Transmission System)

While the Company prefers proposals that are directly connected to the Southern Company transmission system, PPA proposals for Facilities not connected to the Southern Company transmission system will be considered. However, any bidder proposing a Facility not connected to the Southern Company transmission system must demonstrate that it has firm transmission service for the entire term of the PPA to deliver the entire capacity and energy of the Facility to the interface with the Southern Company transmission system. The PPA will include provisions that require the successful bidder(s) to (a) acquire firm physical transmission rights, and (b) guarantee physical delivery of the Company's energy entitlement from the Facility to the designated interface with the Southern Company transmission system. The Company will bear no transmission price or congestion cost responsibilities relative to any transmission service through or out of other transmission systems or balancing authorities. The successful bidder will be responsible for, and proposed prices must include, any costs associated with satisfying the foregoing requirements.

Options to Mitigate Short-Term Transmission Constraints

The Company is seeking PPA proposals for which firm transmission service can be available to serve the Company's loads by the service commencement date and throughout the term of the PPA. The Company recognizes that some proposals could have value to customers but may have potential transmission constraints that are either (i) limited in time, or (ii) could be cured or mitigated by reducing the megawatt capacity of the Facility. In such event, the Company will consider options to cure or mitigate such transmission constraints where (i) a transmission cure cannot be effectuated prior to the required commercial operation date, or (ii) the cost to cure the constraints would make the bid non-competitive. Such options may include, but are not limited to, (i) reducing the capacity amount proposed for a portion of or the entire term of the PPA, (ii) shortening the term of the PPA, (iii) identifying an Alternate Resource or interim resource to supply the capacity and energy during such constrained periods, (iv) providing financial settlement in the form of replacement power cost, or (v) providing financial settlement in the form of liquidated damages.

In determining the applicability of an option, the Company will consider the reliability impacts of implementing the option as well as the value provided by the bid as compared to other proposals. If the Company proposes an option to a bidder, the bidder will not be allowed to change the fixed pricing (capacity and fixed O&M) components. If the solution requires a reduction in the MW capacity of the Facility, the bidder will be allowed to propose changes to the operational characteristics and energy pricing commensurate with the reduction in Facility capacity offered.

Interconnection Guidance

Proposed resources for a PPA will either (i) interconnect to the transmission system of the Company or (ii) be deliverable to the Southern Company transmission system on a firm basis.

Bidders are responsible for submitting requests to interconnect their generation resources and to obtain all relevant information regarding the interconnection process. General information about generator interconnections to the Company's transmission system (>40 kV) can be found on Southern Companies' OASIS website (https://www.oasis.oati.com/SOCO), under the Generator Interconnection folder. If a bidder has a site-specific question about the interconnection process, bidders may submit a pre-application report request, as described on Southern Companies' OASIS website (https://www.oasis.oati.com/SOCO), under the Generator Interconnection/Small Generator Interconnection folder.

The submission of a proposal in response to this RFP does not constitute an interconnection request. Interconnection requests must be submitted to the Company pursuant to the applicable interconnection process. Additional costs associated with submitting an interconnection request may apply. All such costs are the bidder's sole responsibility.

Bidders selected for the "short list" must promptly submit all required interconnection requests, to the extent not already submitted, in order to remain eligible for further consideration under this RFP. Allowing sufficient lead time for study of an interconnection request (typically 12-15 months) and for construction of the required interconnection facilities and upgrades (typically 24 months or longer) is critical to meeting any target in-service date.

Each short list bidder shall provide all relevant information regarding the status of its interconnection request(s), including the interconnection facilities that will be required to interconnect the proposed resource and the costs to interconnect, including any contingent facilities (*e.g.* prior-planned or prior-queued projects). The Company shall be entitled to make inquiries from time-to-time to obtain such information.

Each bidder proposing a PPA for a facility that is interconnected to the Company transmission system will be required to enter into an interconnection agreement (to the extent the resource would interconnect to the Company's transmission system), which carries a monthly administration fee of $5,000 and operations and maintenance charges specific to each project. This monthly administration fee does not vary with project size and is applicable to any bidder proposing a PPA for a Facility interconnected to the Southern Company transmission system. These costs should be considered in the bidder's pricing. The Generator Interconnection Agreement will also require the bidder to provide security for all interconnection costs (including interconnection upgrades, potential tax liability, and any contingent facilities) until the project achieves full commercial operation.

In addition to facilities and upgrades required for interconnection on the Company's side of the interconnection facilities, an important consideration in the evaluation of proposals will be whether there is adequate transmission capability to reliably deliver the energy of a proposed project from the proposed point of interconnection to the Company and its customers for their use. Therefore, the Company, or a designated agent of the Company, will conduct assessments, as appropriate, to determine the costs of any modifications to the transmission system that are necessary to deliver energy from a proposed resource for them to be appropriately considered in the bid evaluation. Also, any Affected System (as defined in the OATT) improvements for interconnection and delivery may require further studies and Affected System improvement agreements with other utilities.

Availability and Alternate Delivery

The Company will rely, in part, on the contracted power supplied by any selected PPA bid to provide dependable and reliable electric service to meet the needs of its customers. Accordingly, the Company will require stringent protection for the Company and its customers against failures by the PPA bidder to deliver contracted capacity and energy in accordance with the PPA. The Company expects that, with the exception of scheduled outages and Force Majeure events, the Facility will be available for dispatch at all times. If the Facility is unable to meet the Company's dispatch schedules, the seller will be responsible for reimbursing the Company for its replacement power costs. However, in lieu of incurring such costs when the Facility is unavailable, the bidder will have the option to meet dispatch schedules with capacity and energy delivered from an alternate resource on a firm basis subject to the alternate delivery provisions in the Pro Forma PPA.

Performance Security

Any PPA that the Company enters into must provide reasonable assurance that the Company will be able to readily recover its actual damages in the event of any default by the seller under a PPA. Accordingly, simultaneously with the execution of the PPA and thereafter for the term of the PPA, the bidder shall provide and maintain performance security in a form and amount acceptable to the Company in order to secure bidder's performance obligations. Such performance security may be in the form of a letter of credit, parent guaranty from a creditworthy guarantor acceptable to the Company, or other security acceptable to the Company. The specific requirements for PPA security are set forth in the Pro Forma PPA. The indicative PPA security "Exposure Risk" requirements are set forth below; however, the Company may determine to increase these security amounts prior to PPA execution, including after consultation with the APSC.

5 Year Exposure Risk ($/kW)	
Combine Cycle	$ 285
Combustion Turbine	$ 70

Environmental

All bidders will be responsible for compliance with federal, state and local environmental laws and regulations including but not limited to regulated environmental air pollutants and emissions that the Facility is subject to. Seller should provide all permits that the Facility is subject to under federal, state, and local environmental regulations as required by the Company for review. The Company will not excuse the delivery of energy as a result of non-compliance with any permit or environmental law or regulation at the Facility

The bidder shall provide the Company with the benefit of an appropriate pro rata portion of all environmental allowances (if any) allocated to the Facility by any governmental authority at no cost to seller. Such pro rata portion of environmental allowances will be equal to the amount of capacity designated to the Company in the PPA proposal. The Company will be responsible for required environmental allowances exceeding the pro rata portion allocated to the Company by the bidder. The specific requirements for PPA environmental requirements are set forth in the Pro Forma PPA.

Energy Price

PPA bidders are encouraged to bid variable costs consistent with their actual realized variable costs. The Company prefers guaranteed variable costs that closely approximate actual unit cost and performance. If the bid variable components are not consistent with design specifications of the Facility, the Company may request that a bidder modify its proposal(s). This cost-based pricing approach should reflect, but is not limited to, the following components:

- Variable O&M
- Start Cost
- Heat Rate

Fixed O&M Price

The Company prefers that fixed O&M cost should be included in the capacity price. However, if a PPA bidder elects to have a fixed O&M price separate from the capacity price, the bid fixed O&M price should be consistent with the bidder's expected actual costs.

Operating Flexibility

Bidders proposing a CC may bid a Facility with 1-on-1 configuration, 2-on-1 configuration, or any other configuration as desired. Bidders of 2-on-1 configured CC Facilities must offer operation in the 1-on-1 mode if technically feasible by design. Operating in 1-on-1 mode entails the ability to operate a single CT, one HRSG and the steam turbine while the second CT is shut off. Bidders of the Facility must offer cycling from 2-on-1 mode of operation down to 1-on-1 mode and back up to 2-on-1 mode if technically feasible by design.

Bidders of 2-on-1 configured CC Facilities should offer pricing for 1-on-1 mode of operation based on the cost of operating in this mode. This should entail a start charge that accurately represents the cost of starting the Facility in the 1-on-1 mode and the cost of moving from 1-on-1 mode to 2-on-1 mode. Bidders should also provide heat rate curves consistent with the actual cost of 1-on-1 mode of operation.

In the event a bidder proposes a resource with other operational capabilities, (*e.g.* 3-on-1 configuration, power augmentation, full pressure), such bidder's proposal must offer the operational flexibility consistent with the Facility capabilities and pricing based on the cost of providing such operational flexibility.

For PPA bids with multiple modes of operation, bidders must specify the guaranteed nominal capacity of each mode and quote a single capacity bid price for the entire output of the Facility and insert those capacities and that price into Attachment C: RFP Bid Form. In the event during any contract year the capacities designated by mode are different from their respective guaranteed nominal capabilities by mode, the seller will be subject to remedies described in the Pro Forma PPA.

Fuel Plan for PPA Proposals

PPA Bidders must provide details regarding the fuel supply plan to the proposed generation Facility they are proposing for a PPA. Any such proposal would have to adhere to the fuel plan provisions provided above in the Operating Parameters and Requirements section in this RFP document.

The Company prefers a fuel tolling arrangement (*i.e.*, an arrangement in which the Company as buyer is responsible for fuel supply and transportation). As an alternative, the bidder may propose a non-tolling agreement.

Tolling PPA Proposals

- With respect to resources for which the bidder does have a pre-existing fuel transportation arrangement, the Company prefers an assignment of the pre-existing fuel transportation arrangement. With respect to resources for which the bidder does not have a pre-existing fuel transportation arrangement, the Company prefers bidder provide a fuel transportation proposal from the connecting interstate pipeline company. The Company would anticipate receiving assignment of the proposal upon execution. The bidder should provide specific data regarding the costs and rates that will be assigned pursuant to the fuel transportation arrangement or any proposal from the pipeline company. All such arrangements must comply with applicable regulatory requirements, and the Company, at its sole discretion, may choose to reject assignment and impute its own supply plan.

- The bidder must propose to assign a pre-existing fuel transportation arrangement or propose a new transportation arrangement to the Company for the term of the PPA or reasonably demonstrate that the Company could secure a fuel transportation arrangement matching the PPA term.

- The Company will be responsible for delivering to the agreed-upon gas delivery point sufficient quantities of natural gas necessary to generate energy pursuant to the Company's energy schedules. The Company shall bear the risk of loss of natural gas until it is delivered to the delivery point. The party responsible for causing any imbalances shall be responsible for payment of any imbalance charges assessed by the pipeline operator.

Non-Tolling PPA Proposals

- In the case of resources for which a PPA bidder does have a pre-existing fuel transportation arrangement and the bidder proposes a non-tolling fuel plan in its bid, then the bidder must provide complete details (e.g., costs, rates, term) of its fuel transportation arrangements and fuel plan with its proposal.

- A successful bidder that proposes a non-tolling fuel plan will <u>not</u> be excused from a failure to meet the Company's energy schedules as a result of the inability to provide natural gas to the Facility unless such an event affects dedicated firm transportation and constitutes a force majeure event under the applicable pipeline tariff, or is the result of an operational flow order that is not directed toward such bidder's failure to comply with the applicable pipeline tariff. Unless excused by the preceding sentence, such bidder shall be responsible to reimburse the Company for its incremental replacement power costs. The PPA will also contain provisions such that if the Company has substantial concerns about the reliability of the Facility due to the fuel plan, the Company shall have the right to take over the fuel supply to the Facility.

Additional Options for PPA Bidders

The Company anticipates that most PPA proposals will be able to conform to the PPA product definition as described above. However, in the event a bidder needs additional flexibility in order to conform to the PPA product definition or to improve the value of a proposal offering given the bidder's circumstances, the following options will be considered by the Company:

1. ***Consolidated Bids***

The Company will accept a consolidated bid submitted jointly by two entities. The bid should be comparable to that submitted by a single entity in all substantive respects. For example, a single bid must include a consolidated performance security response and a clear indication of the party responsible for development, construction, maintenance and operations. For purposes of the relationship with the Company and for bidding into the RFP, the bid will be treated as though it is from a single entity. The Company retains the right to evaluate the bidder's qualifications to perform under the PPA. If the bid is selected, the Company will require that prior to PPA execution the two entities form or designate a single entity, such as an LLC or LLP, to serve as the counterparty.

2. ***Multiple Facilities Bids***

The Company will accept a bid in which a bidder utilizes two separate Facilities to develop a response for a five (5), ten (10), fifteen (15) year, or twenty (20) year term proposal. For example, if a bidder only had the right to capacity and energy of Facility A for 8 years, the options available to the bidder would be as follows:

a) Bid a 5-year proposal from Facility A;
b) Bid a 10-year proposal comprised of 8 years of Facility A and 2 years of Facility B;
c) Bid a 15-year proposal comprised of 8 years of Facility A and 7 years of Facility B.
d) Bid a 20-year proposal comprised of 8 years of Facility A and 12 years of Facility B.

It would be acceptable for such bidder to submit all four proposals; provided, however, that each Facility must be clearly identified and committed to the contract for its portion of the full term, and the bid must include all pricing information (*e.g.*, capacity price, variable O&M, Heat Rate Guarantees, etc.) required by the RFP for both Facilities.

3. ***Term Extensions***

The Company will accept bids that offer a Facility for a 5, 10, 15 or 20-year term and provides the Company an option to extend the agreement for a specified additional term of one to five years. The pricing for the additional term must be no higher in any contract year than the pricing for the final contract year of the conforming term. The Company is not under any obligation to execute the extension. This optionality will be a non-price consideration in the evaluation.

4. ***Early Service Commencement Date***

The Company will accept bids that provide the option to set an early service commencement date (*i.e.*, a point earlier than the service commencement date of December 1, 2023, as defined in the Pro Forma PPA), but no earlier than December 1, 2019. For proposals offering an early service commencement date, bidders should include PPA pricing for each year of the extension. The bidder's proposal offering a service commencement date as defined in the Pro Forma PPA will be evaluated against all other proposals received in the RFP. If the bid is selected as a winning proposal and the bidder is offering an early service commencement date that provides additional value to customers, the parties would execute a PPA with the early service commencement date. If it is determined that the extension does not provide additional value, the parties would execute a PPA with a service commencement date as defined in the Pro Forma PPA. The bidder's pricing information for this option is to be entered in Attachment C in the tab entitled "Early Start Price."

In the event a bidder desires to submit a bid utilizing one or more of the aforementioned options, the bidder should clearly state in the bid(s) that such option(s) is being offered and provide sufficient detail to support the bid. To the extent practical, the bidder should utilize the applicable attachments to this RFP for each Facility offered and provide supplemental information as necessary to communicate the bid terms. For instance, a bidder utilizing the Multiple Facility option would complete Attachments B, C, D, E, F, and G for each Facility and indicate in the bid the periods in which each Facility is offered. The Company reserves the right to request additional information necessary to consider and evaluate the bid.

VIE and Finance Lease Considerations

Given the length of the terms that PPA proposals may cover in response to this RFP, and the business structure a bidder may choose to adopt, accounting and tax rules may require either (i) that a PPA be accounted for by the Company as a

Finance Lease[3] or operating lease, or (ii) the seller under the PPA be consolidated as a Variable Interest Entity[4] onto the Company's books. The Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment. All proposals that are deemed likely to subject the Company to VIE treatment will be rejected and considered a non-conforming bid. At PPA execution, the chief financial officer of seller must provide certification that the Company will not be subject to VIE treatment. Further, any PPA that the Company executes will require that (i) seller covenant that the Company will not be subject to VIE treatment at any point during the term of the PPA, and (ii) in the event that the PPA causes the Company to be subject to VIE treatment at any point during the term of the PPA, unless cured, such treatment will constitute a seller event of default under the PPA. As provided in the Default and Remedies section of the Pro Forma PPA, the Company would have the right to declare such event of default and cause early termination of the PPA. If the seller is unable to clearly demonstrate that the consolidation event was not due to the direct or indirect actions of the seller, the seller will be liable for damages pursuant to the relevant provisions of the PPA.

Due to the expectation of changing guidance and standards in 2019, there will not be a Finance Lease certification in the RFP. However, for evaluation purposes all PPA bidders must represent whether their proposal qualifies as a Finance Lease, based on their personal consideration of the factual matters and their understanding of accounting standards regarding Finance Leases. If the bidder determines that the proposal constitutes a Finance Lease, the bidder must also provide with such bid the amounts that the Company would be expected to capitalize as a result of the PPA. In any case for which the bidder determines the proposal is not a Finance Lease, the bidder is required to provide supporting information sufficient to enable the Company to independently verify that Finance Lease treatment will not occur. The chief financial officer of seller or an officer having responsibilities for financial accounting matters associated with the PPA shall provide the necessary certification at PPA execution. For proposals declared as Finance Leases, the bid evaluation will include the cost to the utility resulting from capitalization of PPA costs on the Company's balance sheet.

Furthermore, each bidder with a proposal selected for the short list of proposals for further evaluation must also agree to make available any and all financial and business data associated with the seller, the Facility and the PPA that the Company would need to independently make its accounting determinations. Such information may include, but may not be limited to, data supporting the economic life, the fair value, investment tax credits associated with or other costs associated with the Facility including debt specific to the asset proposed. Financial data

[3] "Finance Lease" shall have the meaning as set forth in the Accounting Standards Codification ("ASC") Topic 842, Leases, as issued and amended from time to time by the Financial Accounting Standards Board.
[4] "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in ASC Topic 810, Consolidation, as issued and amended from time to time by the Financial Accounting Standards Board.

contained in the bidders' financial statements (*e.g.*, income statements, balance sheets, etc.) may also be required.

Bidder's Qualification Screen and Project Development Requirements

In the event a PPA bid proposing to develop a new project is identified by the Company as one of the most competitive bids, the bidder will be required to submit within two (2) weeks of such selection a certification signed by an officer of the bidder to the effect that the bidder has the ability to implement such project, including a full description of all development activities completed or pending including, without limitation, negotiations for partnership agreements, equipment supplier agreements, financing, permitting, and design work. Note, however, that the bidder must submit, at the time of the proposal, verification that the bidder's contractor(s) are properly licensed to perform such work in the State of Alabama. The Company may require bidders to provide copies of such development documentation as a condition of further evaluation of their proposal(s). It will be the bidder's sole responsibility to obtain any financing associated with the project and any PPA entered into by the Company shall not be contingent upon the bidder obtaining such financing.

Asset Purchase and Sale Agreement Proposals

As indicated above, the Company will consider purchasing existing generating assets as well as new-build/transfer generation facilities (*i.e.*, new facilities to be constructed that will be acquired after substantial completion through a purchase transaction) that are in commercial operation as of the specified delivery period ("APSA bids"). APSA bids will be subject to the receipt of all required regulatory approvals. The bidder must offer 100% ownership of the facility or the business entity owning the facility, including appurtenant works and generation interconnection facilities, rather than just a unit(s) of the facility or percentage ownership of the facility or the owning business entity. Proposed generation facilities should have no major operational limitations that reduce their ability to run for extended periods. The Company will consider the acquisition of a generation facility or facilities owned by multiple owners provided that the owners submit a joint proposal where full ownership of the facility or facilities is being offered. If an APSA bid makes the short list of competitive proposals, the bidder may be asked by the Company to also submit an offer to purchase the business entity that holds the generating asset, if such was not done as part of the initial bid. In the evaluation process, the Company will give preference to proposals that afford it flexibility to purchase either the generating asset or the generating asset together with the business entity.

In the evaluation process, APSA bids will receive comparable treatment to PPA bids. APSA bids must complete Attachments B, C, D, E, F, G, and H, which indicate the information the Company must receive from the bidder in order to perform preliminary evaluation and associated Phase 1 due diligence.

The Company will only accept APSA proposals for generation facilities located inside the state of Alabama and that either are interconnected or have the ability to interconnect to the Southern Company transmission system. Any proposal for the sale of a generation facility or facilities not interconnected to the Southern Company transmission system must include additional interconnection costs in the bid proposal. APSA bids for new-build/transfers should follow the "Interconnection Guidance" section under PPA proposals in this document as it pertains to the facility needs for interconnection.

APSA bidders must provide an "all-in" price that includes all customary and reasonable facilities necessary for the reliable operation of the offered asset, including transmission interconnection, gas lateral, land and any other facilities (the "Asset Facility"). The Asset Facility shall include but not be limited to the asset's major equipment and all auxiliary equipment and facilities necessary or used for the production, control, delivery, or monitoring of electricity produced on the property, as well as the appropriate rights to the land. All equipment and other facilities installed on the bidder's side of the transmission interconnection point and the primary gas delivery point shall be considered a part of the Asset Facility. The proposed prices must include all costs associated with the project up to the point where the project facilities will connect to the interconnection facilities to be constructed and owned by the Company including but not limited to engineering, construction, equipment, insurance, and land. Each project must comply with all the applicable federal, state, and local laws and regulations. All federal, state, and local approvals, permits, licenses, and environmental regulations and associated fees or other costs are the responsibility of the bidder. This includes any rezoning, land-use permits, and other discretionary approvals that may be required by the local, state, or federal governments. All data provided in Attachment C: RFP Bid Forms including capacity, heat rate, O&M costs, startup fuel, and availability for the Asset Facility, must be based on testing, past performance and good faith estimates, as applicable. Bidders should expect the Company to conduct all due diligence assessments deemed necessary, in its sole judgment and discretion, for short-listed APSA proposals to determine cost estimates to own and operate the Asset Facility.

If a bidder proposing an APSA for a new-build/transfer generation facility is a winning bid of competitive proposals, the bidder will be asked by the Company to submit monthly progress reports of construction, meet the project milestones proposed by the Company in the APSA, and may be subject to delay damages if the project does not achieve the commercial operation date by the specified delivery date.

Fuel Supply for APSA

Bidders must provide details regarding the existing fuel supply to the proposed generation facility, as well as a description of anticipated fuel supply agreements in the future. Any such proposal would have to adhere to the fuel plan provisions provided above in the Operating Parameters and Requirements section of this RFP document.

Environmental and Land Information for APSA

All bidder's facilities should be in compliance with federal, state and local environmental regulations including but not limited to regulated environmental air pollutants and emissions that the facility is subject to. The bidder should provide all permits that the facility is subject to under federal, state, and local environmental regulations as well as any historical environmental and land citations against the facility as required by the Company for review.

A legal description of the land being used for the project must be included in the bid in addition to supporting documents to describe the nature of the possession of the real property at the time of construction as either fee simple ownership or lease (e.g., copy of option contract; copy of deed; copy of lease agreement). All documentation that is currently available for the real property must be provided in Attachment C under the tab "Land Information" (e.g., Title insurance / Commitment, Title Abstract, ALTA Survey, Boundary and/or Topographic Survey, Phase 1 Environmental Assessment, Wetland delineations, Threatened & Endangered Species report, Land Patent and Geotechnical Analysis). Any of the above documentation that becomes available at a later date should be supplied at that time. The bidder should include detail information regarding site control of the land.

Due Diligence Assessment for APSA

A short-listed APSA bidder should be prepared to provide, within fifteen (15) days of being so notified, all necessary information to facilitate the performance by the Company of a full Phase 2 due diligence assessment. Much of this data must be made readily available electronically or in a data room setting to be copied and reviewed by the Company. Also, additional data may be required depending on an initial review of the provided information.

- APSA bidders (both existing and new-build/transfer proposals) must submit a preliminary Phase 1 due diligence evaluation fee of $5,000 in addition to the required bidders fee of $10,000 by the RFP deadline of November 9, 2018 by 5:00 pm CST.

- Any APSA proposal for an existing generating facility that is deemed competitive and short-listed after the preliminary Phase 1 due diligence evaluation must submit a Phase 2 due diligence evaluation fee of $250,000 within fifteen (15) days of being so notified. Bidders should refer to Attachment H: Bidder Fees and Due Diligence Fees for more guidance on due diligence fees.

- Any APSA proposal for a new-build/transfer generating facility that is deemed competitive and short-listed after the preliminary Phase 1 due diligence evaluation must submit a Phase 2 due diligence evaluation fee of $400,000 within fifteen (15) days of being so notified. Bidders should refer to Attachment H: Bidder Fees and Due Diligence Fees for more guidance on due diligence fees.

- In addition to a review of all pertinent documentation associated with any APSA bid, the Company's due diligence assessment (for both existing and new-build/transfer APSA proposals) will require on-site visits by a Company team, including personnel from all Company areas required for an adequate assessment of the proposed generation resource, including but not limited to the following:

    - Generation Project Development
    - Accounting
    - Operations
    - Finance
    - Maintenance
    - Legal

<u>Notice of Intent to Bid ("NOI") Submittal Process</u>

1. All bidders must complete the forms listed below for their proposed bid type project located in Attachment B: Notice of Intent to Bid "NOI" Forms on the RFP website, www.alabamapower.com/our-company/how-we-operate/capacity-rfp.html.

<u>For a PPA project</u>

- NOI Form
- Bidder's Questionnaire
- Confidentiality Agreement
- Contractor Compliance Background Certification Form
    - Documentation supporting bidder's credit quality and verification of appropriate state contractor's licenses (for new projects)
- Contact(s) for the RFP Process

<u>For an APSA project</u>

- NOI Form
- Bidder's Questionnaire
- Confidentiality Agreement
- Contractor Compliance Background Certification Form
    - Verification of appropriate state contractor's licenses (for new-build/transfer APSA projects)
- Contractor Statistical Data (Employee Modification Rate or EMR)
- Contact(s) for the RFP Process

2. If a bidder is submitting more than one proposal, one NOI form must be submitted for each proposal. This includes every version of the same project that is being proposed. Only one submission of the other required forms is necessary for each bidder unless the information on the other required forms varies among the project(s) submitted.

3. Bidders must submit the NOI forms in order for the Company to send the electronic payment information to the provided contacts for the bidder's evaluation fee and due diligence fees.

4. The required forms must be sent by 5:00 pm CDT on October 5, 2018 by emailing them using the following email address: G2APCRPRFP@southernco.com and by sending one hard copy of the required forms through registered mail, addressed as follows:

Forecasting & Resource Planning
APC Capacity RFP
600 North 18th Street / 6N-0603
Birmingham, AL 35203

Emailed files **CANNOT** be received as a .ZIP file, be greater than 20MB in size, or posted in a file sharing folder (e.g., DropBox® or Google Docs™).

Bid Evaluation

Bid proposals submitted pursuant to this RFP will be considered and evaluated together. Such evaluation will include a review of transmission and ancillary service requirements, as appropriate, to determine the total cost impacts. Please note that the Company may revise its capacity need forecast to reduce, eliminate, or increase the amount of power sought, or change the schedule for this RFP, at any point during the RFP process or negotiations. Further, this RFP and the documents are subject to modification or withdrawal at any time in the sole discretion of the Company.

Bidder Evaluation Fees; Multiple Bids

For each project submitted, there will be a nonrefundable bidder evaluation fee ("Bid Fee") of $10,000. Electronic payment for the bid evaluation fee is to be made to Alabama Power Company.

The bid is not complete and will not be evaluated unless the appropriate Bid Fee has been received by the RFP deadline of 5:00 pm CST on November 9, 2018. Utilizing the guidance of the following paragraph, the Company shall determine in its sole discretion whether a bidder's proposals constitute one or more proposals for purposes of assessing the foregoing fees.

Bidders may submit multiple bid proposals in response to this RFP. Bid proposals for the same site and the same generation technology and size that are offered with options in the fuel plan and/or fixed cost components will be considered a single bid proposal. In addition, bid proposals for the same site containing options in the number of generating units offered or portions thereof will be considered a single bid if the generation technology is the same and the operational parameters and variable pricing are the same in all proposals. In the event a bidder submits separate proposals that vary regarding certain critical parameters, including but not limited to the site, output, electrical characteristics, and technology *(e.g.*, CT, CC, cogeneration, primary fuel), such bidder will be required to pay a Bid Fee of ten thousand dollars ($10,000) for each such proposal.

Submission of PPA proposals for five (5), ten (10), fifteen (15) and twenty (20) years with all performance and variable pricing characteristics remaining the same shall be considered one bid.

A separate NOI form also must be submitted for each version of the project, whether or not there is a separate Bid Fee.

For APSA proposals, bidders will also be required to submit all "due diligence fees", including both the preliminary Phase 1 due diligence fee and the Phase 2 due diligence fee for short-listed APSA proposals. Further information is provided in Attachment H: Bidders Fees and Due Diligence Fees

Company's Reservation of Rights and Disclaimers

The Company reserves the right, without qualification and in its sole discretion, to reject as non-responsive any bid proposals received for failure to meet any requirement of this RFP. Any proposal that does not satisfy the requirements of this RFP may be considered nonresponsive, and the Company reserves the right to reject any such proposal without opportunity for correction or cure. By way of example and not by limitation, the following shall constitute non-responsive bids: a bid proposal offering non-firm capacity, a demand-side bid proposal, an uncured, incomplete or non-specific bid proposal or a bid proposal that fails to materially comply with the provisions of the Pro Forma PPA. The Company also reserves the right to contact any bidder for additional information or to cure a deficiency in the proposal.

The Company further reserves the right without qualification and in its sole discretion to decline to enter into a PPA or APSA with any bidder for any reason. Nothing in this RFP or in the associated materials provided should be considered an offer or acceptance of terms or conditions of a PPA, an APSA, an interconnection agreement, or any other contract or business arrangement. The Company shall have no obligation or liability to any bidder unless and until an agreement with such bidder has been successfully negotiated, fully executed, and all conditions to the effectiveness of such agreement are satisfied. The Company reserves the right, in its sole discretion, to determine whether to pursue negotiation and execution of any agreement with any bidder. Further, any agreement shall be subject to all requisite management approvals of the Company as well as approval by the APSC in a form suitable to the Company, in its sole and absolute discretion.

Each bidder who submits a proposal(s) in response to this RFP waives any and all right of recourse against the Company, its parent, and any of their affiliates for either rejection of the proposal or for failure to execute an agreement with the bidder for any reason or for any modification or withdrawal of this RFP. The Bid Fees submitted by any bidder will not be refunded (unless otherwise determined in the sole discretion of the Company) in the case of any modification or withdrawal of this RFP, rejection of any bid proposal for non-responsiveness or other reason, failure to execute a PPA, or failure to execute an APSA. All costs related to each bidder's preparation of a response to this RFP are the sole responsibility of the bidder. The Company will not reimburse or be held responsible for costs associated with any bidder's proposal in response to this RFP.

A bidder's submission of a proposal to the Company shall constitute that bidder's acknowledgement and acceptance of all the terms, conditions, and requirements of this RFP. All proposals submitted shall become the exclusive property of the Company and may be used by the Company for any reasonable purpose.

Proposals submitted pursuant to this RFP will be evaluated in whatever manner the Company deems appropriate, including (but not limited to) on a like-kind basis against each other (independent of technology type) and against other power supply options that may be available to the Company. Such other power supply options may include generation resources owned or developed by the Company, other generation resources located in the service territories of the Company and its affiliates, and other proposals for capacity that are provided to the Company outside of this RFP process. The Company is under no obligation to select any project, nor is the Company limited to choosing from the resources submitted in response to this RFP.

<u>Tentative Solicitation Schedule</u>

DATE	EVENT
September 21, 2018	Solicitation Issued
October 5, 2018	NOI Deadline
November 9, 2018	Bid Proposals Deadline
May 29, 2019	Short List/ Reserve List Determination

<u>Guidance to Bidders and Instructions for Completing Forms</u>

1. Frequently Asked Questions ("FAQ") will be posted to the RFP website (www.alabamapower.com/our-company/how-we-operate/capacity-rfp.html) and updated periodically with repetitive questions and responses.

All bidders must complete and submit Attachment B: Notice of Intent to Bid "NOI" Forms by the NOI deadline, October 5, 2018 by 5:00 p.m. CDT. Bidders must submit the NOI forms in order for the Company to send the electronic payment information for the bidder's evaluation fee and due diligence fees to the provided RFP bidder contacts.

2. Each bidder must submit an electronic copy of bid proposals to G2APCRPRFP@southernco.com and by sending one hard copy of the required forms through registered mail, addressed as follows:

Forecasting & Resource Planning
APC Capacity RFP
600 North 18th Street / 6N-0603
Birmingham, AL 35203

All bid proposals and fees must be received by 5:00 pm CDT on November 9, 2018. Any bid proposal that does not contain **all** of the required information by 5:00 pm CST on November 9, 2018 will be subject to rejection as non-responsive by the Company.

Emailed files **CANNOT** be received as a .ZIP file, be greater than 20MB in size, or posted in a file sharing folder (e.g., DropBox® or Google Docs™).

3. Each bidder must submit a hard copy of the original bid signed by an officer (i.e., president, vice president, etc.) of the bidding company. The signed hard copy of the original bid proposal should be submitted in a three-ring binder with transparent pockets on the front cover and the spine mailed to:

Forecasting & Resource Planning
APC Capacity RFP
600 North 18th Street / 6N-0603
Birmingham, AL 35203

4. In the event that a bidder discovers an error or omission in the bid after submitting hard copies, the bidder must note any changes in the electronic copy and such changes must be sent to G2APCRPRFP@southernco.com by 5:00 pm CDT on November 9, 2018. In the event of a discrepancy between the electronic form and the hardcopy form of the bids submitted, the electronic form will be considered to be correct. In addition, one corrected hard copy must be received by the Company within three business days of the filing deadline.

5. For each PPA bid, bidder must include a copy of the Pro Forma PPA (Attachment G) with (i) all blank spaces completely filled in except those that are to be completed by the Company, (ii) any and all proposed changes to the Pro Forma PPA shown with specificity in a mark-up and accompanied by a summary of such changes, including the specific identification of any changes to the PPA being requested by a third party if the bidder is subject to a third party agreement, and

(iii) a statement by the bidder that the terms and conditions of the applicable Pro Forma PPA as proposed by the bidder are acceptable to the bidder.

6. A PPA bidder may submit a proposal sourced from a Facility owned by another entity if the bidder has a contractual unencumbered first-call right to capacity and energy from the Facility (*e.g*., a tolling agreement). The bidder must include the modifications to the Pro Forma PPA necessary to conform the Pro Forma PPA to that agreement. However, the Company will only accept changes that, when taken as a whole, the Company determines do not materially affect the value to customers and risk allocation inherent in the Pro Forma PPA. Such changes should be limited to those specific to operations, scheduling and maintenance, including any limitations on the Facility's operations, inherent to the pre-existing agreement. The bidder is encouraged to submit a redacted version of the pre-existing agreement along with the Pro Forma PPA. However, the bidder is not required to submit such agreement with the bid if the bidder provides a markup of the Pro Forma PPA incorporating the provisions necessary to conform to the Pro Forma PPA. The Company will require submission of such agreement if the proposal subsequently is considered one of the more competitive proposals. The bid evaluation will consider whether the bidder's proposed changes can be accommodated, and if so, will conduct a quantitative and qualitative evaluation of the impact of such proposed changes. If the bidder's proposed changes cannot be accommodated, the bid may be rejected.

7. The concepts and material provisions of the Pro Forma PPAs are non-negotiable except as provided in these instructions. Bidder's proposals must conform to the Pro Forma PPAs in all material respects except where (1) the bidder offers provisions that the Company determines do not materially affect the value to customers and risk allocation inherent in the Pro Forma PPA provisions, or (2) the Pro Forma PPA assumptions do not conform to the specific characteristics of a proposal. For example, if a bidder's proposal conforms with the requirements of the RFP and the bidder offers a fuel other than natural gas or a secondary fuel supply, then the bidder may propose changes to the applicable Pro Forma PPA, only to the extent needed, to conform a Pro Forma PPA's provisions to such fuel supply factors. The Company will consider the bidder's proposed changes as part of the evaluation of the proposal. The Company may propose its own changes to conform the Pro Forma PPA to the bidder's proposal and may discuss proposed changes with the bidder before making a decision on the bidder's proposal. Depending on the type of proposal that a bidder is offering, more extensive changes to the Pro Forma PPA may be needed. In accordance with these instructions, if the bid is conditioned on any changes to the applicable Pro Forma PPA, then the bidder must expressly so state and must provide the specific language changes that the bidder proposes to the applicable Pro Forma PPA by red-lining the copy of the Pro Forma PPA attached to the bid such that it shows the specific additions (bold and underlined) and deletions (strike-through) that the bidder proposes.

8. All rates for PPA bid proposals should be submitted with escalation rates at (1) Actual GDPIPD/CPI (and will be evaluated based on projected GDPIPD/CPI) or (2) a fixed, annual escalation rate that (a) does not exceed the projected cumulative GDPIPD/CPI over the term of the agreement, (b) does not have any year with a negative escalation rate, and (c) does not have any year with greater than four percent (4%) escalation rate.

9. All energy prices must be quoted as dollars per megawatt-hour ($/MWh) (as applied to variable operation and maintenance ("VOM")) and as heat rates (as applied to fuel cost), if applicable.

10. PPA bid proposal prices must include all costs that the bidder expects the Company to pay for the capacity and energy proposed. The Company will not be responsible for any other costs associated with the project, including but not limited to, station service, test energy, fuel for testing, gas lateral construction, electrical interconnection and all costs incurred necessary to accomplish synchronization.

<u>Compliance with Laws; Regulatory Approvals</u>

1. It shall be the complete and sole responsibility of the bidder to take all necessary actions to satisfy any regulatory requirements, licenses and permits that may be imposed on the bidder by any federal, state or local governmental authority concerning the permitting, development, construction, operation, maintenance, addition, renewal, retirement and disposal of the Facility, or concerning the generation, sale and/or delivery of power. The Company will cooperate with the successful bidder(s) to provide information or such other assistance, as may reasonably be requested by a bidder to satisfy such regulatory requirements. The bidder shall likewise provide such information and assistance to the Company in connection with the Company's regulatory approvals.

2. The Company must receive authorization from the APSC for approval of any PPA or APSA entered into by the Company. Each agreement shall be conditioned on the receipt of all requisite approvals, without material modification, from governmental authorities (including the APSC).

<u>Frequently Asked Questions ("FAQs")</u>

1. What types of generation projects will be considered? A project must be fully dispatchable and available year-round, with an emphasis on availability in both the summer (June-September) and winter (December-February) seasons. Energy storage and any combination thereof is acceptable for this RFP as long as the operating requirements specified in this document are met.

2. **Should I bid a solar facility in this firm capacity RFP or in the Renewable RFP?** A solar facility can be proposed in this Capacity RFP; however, it must be paired with some type of energy storage or other type of generator and must be dispatchable, have Automatic Generation Control ("AGC"), and meet other operating requirements, as applicable, specified in this RFP document.

3. **What size project can be proposed?** Each project proposal, including an aggregate of units at a facility, must be at least one hundred megawatts (100 MW) in total capacity for the resource proposed and no single resource should exceed twelve hundred megawatts (1,200 MW).

   Example 1: If Facility A has two 70 MW units then a bidder must bid both units as a complete resource for a total resource capacity of 140 MW.

   Example 2: If Facility B has Unit 1 with a capacity rating of 1,300 MW and Unit 2 with a capacity rating of 1,000 MW, only Unit 2 qualifies to be proposed in this RFP.

4. **Where must projects be located?** For Power Purchase Agreements ("PPAs"), Alabama Power's preference is that at all times during the PPA service term facilities must be directly interconnected to the Southern Company transmission system (this is a non-quantitative factor in the evaluation); however, for facilities not interconnected to the Southern Company transmission system at any time during the service term must obtain firm transmission service to the Southern Company transmission interface and provide the name of the balancing authority area in which the project is located. For Asset Purchase and Sales Agreements ("APSAs"), the project must be interconnected or have the ability to interconnect to the Southern Company transmission system and must be located in the state of Alabama.

5. **When must the projects be operational?** For PPAs, the service commencement date should be December 1, 2023. However, an early service commencement date as early as December 1, 2019 may be offered as a PPA option. For APSAs, existing facilities may be acquired as early as November 1, 2019, subject to receipt of required regulatory approvals. No proposal will be accepted with a commercial operation date after December 1, 2023.

6. **Is there a limit to the number of proposals one company can submit?** No. There is no limit on the number of proposals from an entity; however, separate bid evaluation fees may be required for each proposal as described in the Capacity RFP document. Regardless of the fee requirement, a separate "Notice of Intent to Bid" form must be submitted for each proposal.

7. **What is the Bidder's fee for a project submittal?** For each project submitted, there will be a nonrefundable bidder evaluation fee of $10,000. If the same project is being submitted with a change to the business arrangement, the additional proposal must have a separate bid evaluation fee of $10,000. However, if a PPA project is being proposed

and there is only a contract term change (e.g., 5-year versus 20-year), no additional bid evaluation fee is required.

Electronic payment for the bid evaluation fee is to be made to Alabama Power.
Bidders must submit the NOI forms in order for the Company to send the electronic payment information for the bidder's evaluation fee and due diligence fees to the provided RFP bidder contacts.

The bid is not complete and will not be evaluated unless the appropriate bid evaluation fee has been received by the RFP deadline of 5:00 pm CST on November 9, 2018.

8. **When is the best time to submit an interconnection study request?**
   While an interconnection study request will not be required until a short list is determined, there is a potentially long study time and construction lead time that could impact the commercial operation date of a project. Information for submitting an interconnection request is available to the bidders in the "Interconnection Guidance" section under PPA proposals in the RFP document.

9. **What should the price of the project include?** The proposed project price (for PPAs, and APSAs) should include the land and facilities associated with the project up to the point of interconnection. This price should include all ongoing operation and maintenance costs for the project facilities up to the point of interconnection, including the monthly administration fee under the interconnection agreement (applicable to bidders proposing a PPA with the Company) for the term of that agreement.

10. **Will there be an opportunity later to change the price offered?** Only as a result of extraordinary circumstances as determined solely by the Company.

11. **Will evaluation details such as avoided costs and proposal rankings be made available?** No. These items are considered confidential and will not be provided to the bidders or to the public.

RFP Attachments Summary

All RFP attachments are available for bidders to download from the RFP website. This RFP document and attachments with forms will be available on the RFP website until November 9, 2018. Below is a summary of the attachments and their associated forms.

Attachment A: Non-Price and Other Qualitative Considerations

Attachment B: Notice of Intent to Bid ("NOI") Forms

For a PPA

1. NOI Form

2. Bidder's Questionnaire
3. Confidentiality Agreement
4. Documentation Support
5. Contact(s) for RFP Process

For an APSA

1. NOI Form
2. Bidder's Questionnaire
3. Confidentiality Agreement
4. Contractor Compliance Background Certification Form
5. Contractor Statistical Data (Employee Modification Rate or EMR)
6. Contact(s) for RFP Process

Attachment C: RFP Bid Forms

For a PPA

1. PPA Instructions
2. General Information
3. Operating Parameters
4. Fuel Supply Plan
5. PPA Pricing Summary
6. Generation Annual Monthly Info
7. Early Start Pricing
8. Land Information

For an APSA

1. General Information
2. Operating Parameters
3. Fuel Supply Plan
4. Land Information
5. APSA Bid Price

Attachment D: Interconnection Information Summary

Attachment E: Environmental Assessment Questionnaire

Attachment F: Stability Analysis Information

Attachment G: Pro Forma PPA

Attachment H: Bidder Fees and Due Diligence Fees

Direct Testimony of John B. Kelley

Exhibit JBK-3

CONFIDENTIAL AND OMITTED

Direct Testimony of John B. Kelley

Exhibit JBK-4

CONFIDENTIAL AND OMITTED

Direct Testimony of John B. Kelley

Exhibit JBK-5

CONFIDENTIAL AND OMITTED

Direct Testimony of John B. Kelley

Exhibit JBK-6

CONFIDENTIAL AND OMITTED

Direct Testimony of John B. Kelley

Exhibit JBK-7

CONFIDENTIAL AND OMITTED

Direct Testimony of John B. Kelley

Exhibit JBK-8

CONFIDENTIAL AND OMITTED

Direct Testimony of John B. Kelley

Exhibit JBK-9

CONFIDENTIAL AND OMITTED

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. ________**

DIRECT TESTIMONY OF JEFFREY B. WEATHERS
ON BEHALF OF ALABAMA POWER COMPANY

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jeffrey B. Weathers. I am the Manager of Resource Planning for Southern Company Services, Inc. ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A: I graduated from Auburn University in 1996 with a Bachelor of Science in Mechanical Engineering, and in 1998 with a Master of Business Administration degree. I began my career at Southern Company in 1998 at Plant Farley and joined SCS in 1999. Over the next seven years, I progressed through roles of increasing responsibility in System Planning, Fleet Operations, Asset Management, and Southern Power Generation Development. I became the Energy Analysis Manager in 2006 with responsibility for analyzing wholesale contracts, trading, and pool transactions. In 2011, I became Manager of Financial and Contract Services, with responsibility for the wholesale billing, settlement, and analysis of the Intercompany Interchange Contract ("IIC"), the wholesale contracts of the operating companies, and the Open Access Transmission Tariff. In December 2015, I moved into the role of Strategic Generation Planning Manager, with responsibility over energy budgeting, scenario planning and forecasting, and asset valuations. In September 2016, I was named Resource Planning Manager and assumed additional responsibilities related to the coordinated planning process.

Q: DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES AS MANAGER OF RESOURCE PLANNING.

A: My responsibilities generally include system integrated resource planning, energy budgeting, system reliability and reserve margin analysis, support for Requests for Proposals and other capacity procurement efforts, scenario planning and forecasting, and production cost modeling and analysis.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: Alabama Power has petitioned the Alabama Public Service Commission ("APSC") for a certificate of convenience and necessity, by which the Company would be granted the authority to acquire certain rights and assume certain obligations relating to several generation resources. As reflected in the testimony of Mr. Kelley, the IRP results shown for Alabama Power, coupled with other factors impacting reliable long-term supply, demonstrate a need for the Company to add approximately 2,400 MW of additional resources by the 2023-2024 timeframe. The purpose of my testimony is to explain in further detail the process used to establish the Target Reserve Margins reflected in the IRP, which are an important part of the process used to determine Alabama Power's indicated need over the stated time horizon. By satisfying this need, Alabama Power will have adequate resources to reliably serve its customers.

Q. WHAT IS "RESOURCE ADEQUACY"?

A. Resource adequacy is the process by which a utility determines the appropriate level of resources to maintain reliability on its system. Accepted utility practice requires that electric utilities maintain a sufficient amount of supply- and demand-side resources to adequately serve the electricity needs of its customers. Alabama Power regularly evaluates resource adequacy through its assessment of system resources, forecasting of peak demand, and determination of appropriate reserve margins.

Q. WHAT IS THE RESERVE MARGIN AND WHAT IS ITS PURPOSE?

A. The reserve margin is the difference between the Company's total existing and committed capacity, including the impact of demand response programs, and the Company's projected peak demand. The reserve margin is generally expressed as the percentage of existing and committed capacity above the projected weather-normal peak demand (e.g., a reserve margin of 16.25 percent means that capacity resources are 16.25 percent above the projected weather-normal peak demand). In accordance with accepted utility practice, Alabama Power maintains capacity reserves greater than the Company's projected peak demand in order to achieve the desired level of reliability in light of various risk factors (such as weather, economic growth uncertainty, generator unit performance, and market availability risk) that could cause the actual peak demand, or generation available to meet the peak demand, to differ from projections.

Q. WHAT IS THE TARGET RESERVE MARGIN?

A. The Target Reserve Margin is the reserve margin that the Company uses for reliability planning purposes. The actual reserve margin will vary over time due to variations in the actual peak demand and resource availability, among other things. In contrast, the Target Reserve Margin remains fixed (until updated on the basis of a Reserve Margin Study) and is used to guide the Company's resource planning decisions. The Company evaluates three components in determining the Target Reserve Margin: economics, risk tolerance and reliability. The Target Reserve Margin is set at a level that will minimize the combined expected costs of maintaining reserve capacity, production costs, and customer costs associated with service interruptions, while adjusting for risk and maintaining a minimum level of reliability.

Q. HOW DOES THE COMPANY DETERMINE ITS TARGET RESERVE MARGIN?

A. A Reserve Margin Study is conducted by SCS for the Southern Company system at least every three years. The study identifies the Target Reserve Margin for the system considering the costs and risks, as just described, to customers and the reliability of the system. The target planning reserve margin for each of the retail operating companies is then determined, taking into consideration the benefit of load diversity. A copy of the 2018 Reserve Margin Study, which is the most recent Reserve Margin Study for the Company and the Southern Company system, is attached to my testimony as Exhibit JBW-1.

Q. HOW DOES THE RESERVE MARGIN STUDY DIFFER FROM THE IRP ANALYSES?

A. The Reserve Margin Study is similar to other analyses underlying the IRP, in that it uses production cost techniques to simulate the operation of the system. However, unlike other IRP analyses, which are based on weather-normal conditions, the Reserve Margin Study evaluates the system under a broad set of system conditions, such as the impact of economic uncertainty on loads as well as the impact of historical weather variations on both loads and resources.

Q. WHY IS THE RESERVE MARGIN STUDY CONDUCTED AT A SYSTEM LEVEL?

A. Because the Southern Company system is operated as a pool pursuant to the IIC, it is appropriate to conduct the Reserve Margin Study at the system level.

Q. WHAT ARE THE TARGET RESERVE MARGINS USED IN ALABAMA POWER'S 2019 IRP PROCESS?

A. The Company is taking steps to ensure that it can adapt its planning processes to meet the changing demands of the system to reliably meet the energy needs of its customers for the foreseeable future. To ensure proper reliability and economics, the Company evaluates the required amount of resources needed above forecasted peak demand, or reserve margin, to establish a Target Reserve Margin for the system for both the short-term and the long-term planning horizons. The Company is maintaining the current 16.25 percent long-term Target Reserve Margin for the summer for use in the summer peak planning season. This Target Reserve Margin is calculated as it traditionally has been, by comparing resources available in the summer – at their summer peak period capacity – to the forecasted weather-normal summer peak load. Additionally, to address winter reliability concerns, the Company has adopted a long-term Target Reserve Margin of 26 percent for application to the winter peak planning season. This 26 percent reserve margin is calculated based on winter peak period resource capacities and the forecasted weather-normal winter peak load. For the short-term, the Company plans to increase the Summer Target Reserve Margin from 14.75 percent to 15.75 percent, with a commensurate short-term Winter Target Reserve Margin of 25.5 percent. As explained in the Reserve Margin Study, the gap between the long-term and short-term periods (regardless of season) has reduced from roughly 1.5 percent to 0.5 percent.

Q. WHY ARE DIFFERENT TARGET RESERVE MARGINS USED FOR SHORT- AND LONG-TERM PLANNING?

A. Over the short-term (inside three years), there is typically less economic uncertainty and therefore, a lower target planning reserve margin can be used for short-term planning than is used for long-term planning.

Q. EXPLAIN WHY THE COMPANY IS ADOPTING SEASONAL PLANNING.

A. Historically, the Company's capacity planning decisions have been driven by a combination of summer peak loads and a corresponding summer-based Target Reserve Margin. These planning techniques have proven to be successful in supporting reliability while cost-effectively meeting the needs of customers in all seasons of the year. The Company is not changing its summer-based Target Reserve Margin of 16.25 percent. However, operational experiences, coupled with a review of historical data, forecasted conditions, and other factors, indicate a significant shift in reliability risk from the summer season to the winter season, thus requiring the Company to adapt its historically summer-based capacity planning approach to specifically address these risks. Therefore, the Company has adopted seasonal planning to address the winter reliability issue first identified in the previous reserve margin study. Seasonal planning, with corresponding seasonal target reserve margins, provides greater visibility into both summer and winter capacity needs rather than limiting reliability decisions to a single season.

Q. DESCRIBE THE PRINCIPAL RISKS THAT CAUSED THE COMPANY TO ADOPT SEASONAL PLANNING.

A. Prior to the 2014 Polar Vortex, the Southern Company system as a whole had experienced an extended period of relatively mild winter weather. During that time, however, the system was also undergoing significant changes in its peak loads and generation resources. In addition, and as discussed in Mr. Kelley's testimony, Alabama Power itself had begun to experience weather normalized winter peak conditions that exceeded its summer peak conditions. These changes, and particularly the responsiveness of the system to cold weather, did not have the opportunity to manifest themselves until the 2014 Polar Vortex and therefore had not previously been modeled in any reliability studies.

Q: WHEN DID SOUTHERN COMPANY BEGIN A MORE FOCUSED ANALYSIS OF THE EFFECTS OF CHANGING WINTER CONDITIONS ON RESOURCE ADEQUACY?

A: The 2015 Reserve Margin Study was the first study that included assumptions and modeling impacts to capture these changes and reflected a significant increase in winter reliability risks. That study identified several underlying drivers, including: (1) narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) cold-weather-related unit outages; (4) penetration of solar resources; and (5) increased fuel transportation risk.

Q: WHY WAS SEASONAL PLANNING NOT ADOPTED AT THAT TIME?

A: At that point in time, the system's experiences with changing winter conditions remained relatively recent, and the consensus among the planning organizations was that an increase in the summer Target Reserve Margin to 16.25 percent would serve to address added reliability risks in the winter season.

Q: WHY DID THE 2018 RESERVE MARGIN STUDY MOVE TO SEASONAL PLANNING?

A: The 2018 Reserve Margin Study not only re-identified the continued persistence of the five risks enumerated above, but also identified a sixth driver associated with market purchase availability under both extreme summer and winter conditions. Upon further consideration and examination of these six reliability risks, the need for a broader seasonal planning approach became evident. Specifically, given the risk of higher than normal winter loads as well as differences in both availability and dependability of resources in the summer and winter peak periods, it has become necessary to independently evaluate resource adequacy in both the summer and winter peak periods to ensure that system reliability has been adequately evaluated and addressed.

Q: HAS THE COMPANY UNDERTAKEN OTHER MEASURES TO ADDRESS CHANGES IN WINTER CONDITIONS BEYOND ADOPTION OF A WINTER TARGET RESERVE MARGIN?

A: Yes. The Company has taken operational and maintenance actions to help address the concerns related to winter reliability risks. The Company has put in place measures to mitigate risks from cold weather outages such as establishing a freeze protection program, incorporating extreme weather scenarios into the winter operational readiness assessments, and avoiding planned unit outages in January and February unless required for environmental or other compliance-related reasons. The Reserve Margin Study modeled expected improvements to historical plant performance associated with the ability of the fleet to better withstand cold temperatures.

Q. WHY IS THE WINTER TARGET RESERVE MARGIN HIGHER THAN THE SUMMER TARGET RESERVE MARGIN?

A. Numerically, the winter Target Reserve Margin is higher than the summer Target Reserve Margin. This largely is a function of the reserve margin calculation (i.e., resources less peak load, divided by peak load), as the forecasted system winter peak loads are lower than the forecasted summer peak loads.

For every summer reserve margin there exists an equivalent winter reserve margin that, for the same given system conditions, represents the same cost and reliability. In fact, as explained in the 2018 Reserve Margin Study, the 26 percent long-term winter Target Reserve Margin is consistent with the results of the 2015 Reserve Margin Study if it had generated an equivalent winter Target Reserve Margin for the system.

Q: IS THE WINTER TARGET RESERVE MARGIN AN EXACT EQUIVALENT OF THE SUMMER TARGET RESERVE MARGIN?

A: No. While this was the case in the 2015 Reserve Margin Study, the 26 percent winter Target Reserve Margin in the 2018 Reserve Margin Study is 1.3 percent higher than the winter equivalent of the 16.25 percent summer Target Reserve Margin, which is 24.7 percent. The additional 1.3 percent is needed to maintain the Company's reliability threshold and provides economic value for customers. This conclusion is supported by the Company's assessment, consistent with industry practice, that a minimum level of system reliability should be a loss of load expectation ("LOLE") of 0.1 days/year (often referred to as a 1:10 – one in ten – LOLE Threshold). Figure V.1 in the Reserve Margin

Study shows that, if the 16.25 percent reserve margin is held in the summer, then 26 percent is needed in the winter for reliability to meet the 1:10 LOLE Threshold criteria. The additional 1.3 percent also provides economic benefits for customers through reduction in the risk of higher cost outcomes.

Q: DOES THE ADOPTION OF SEASONAL PLANNING CONSTITUTE A CHANGE IN THE RESERVE MARGIN STUDY METHODOLOGY?

A: No. Other than adding an additional seasonal look, the Company has not changed its reserve margin study methodology. The Reserve Margin Study continues to evaluate a range of reserve margins to assess the following three criteria: (1) Total System Costs (via the U-Curve); (2) Economic Risk (via the Value at Risk analysis); and (3) System Reliability (via the LOLE evaluation). As described in the 2018 Reserve Margin Study, three separate analyses were included: a traditional analysis; a winter focused analysis; and a summer focused analysis. All three analyses were performed using the same techniques employed in the 2012 Reserve Margin Study and 2015 Reserve Margin Study except for the updated assumptions and minor methodological adjustments. For example, the winter focused analysis used the same assumptions as the traditional analysis except that load shapes were calibrated to the forecasted winter peak demand rather than the forecasted summer peak demand.

Q. WHAT DOES THE ADOPTION OF SEASONAL PLANNING REVEAL AS TO ALABAMA POWER'S RELIABILITY NEEDS?

A. As reflected in the Company's IRP, and as discussed in the testimony of Mr. Kelley, Alabama Power's winter reserve margin is projected to be below both its diversified long-term winter Target Reserve Margin (25.25 percent) and its diversified short-term winter Target Reserve Margin (24.75 percent). Resolving the shortfalls in the winter periods with resources available year-round will also resolve any shortfalls occurring during corresponding summer periods.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	)
	)
Petitioner	)

DIRECT TESTIMONY OF JEFFREY B. WEATHERS
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA	)
COUNTY OF JEFFERSON	)

Jeffrey B. Weathers, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Jeffrey B Weathers

Jeffrey B. Weathers

Subscribed and sworn to before me
this 4th day of September, 2019.

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

Notary Public

Direct Testimony of Jeffery B. Weathers

Exhibit JBW-1

PUBLIC VERSION

An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System

January 2019

Southern Company

EXECUTIVE SUMMARY

Electric utility customers expect and depend on high levels of service reliability. As such, a prudent utility must have an economically balanced level of generating capacity that both exceeds the peak load and that also meets a minimum reliability threshold. To have this reserve capacity available when it is needed, a utility must plan beyond the upcoming season because the processes to procure capacity, such as building a new unit or procuring a power purchase agreement (“PPA”), can take several years to complete. The purpose of this Economic and Reliability Study of the Target Reserve Margin (“Reserve Margin Study”) for the Southern Company System (“System”) is to determine the amount of reserve capacity – or the Target Reserve Margin (“TRM”) – that should be maintained on the System. The Reserve Margin Study includes the companies that participate in the Intercompany Interchange Contract (“IIC”). Specifically, the Reserve Margin Study includes Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and the portion of Southern Power Company included in the IIC (collectively, the “Operating Companies”).
Although the TRM will be used to establish the long-term expansion plan, the 2018 Reserve Margin Study should not be understood to determine one constant reliability index in perpetuity, but rather should be re-evaluated on a periodic basis as the System evolves over time. The results of long-term, constant reliability constraints can be impacted by projected changes in load shapes, unit costs, unit availability, and other factors. The objective is to determine how these constraints affect the next capacity decision, with subsequent re-evaluations modifying downstream decisions, as appropriate.

Traditionally, the TRM has been stated in terms of summer peak demands and summer capacity ratings according to the following formula:

$$TRM = \frac{TSC - SPL}{SPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TSC = Total Summer Capacity; and
SPL = Summer Peak Load.

This traditional representation is essentially a Summer TRM and has been the only reserve margin considered because the System (in aggregate) has always been and remains summer peaking on a weather-normal basis. However, reserve margins can just as easily be stated in alternate terms. Because of increased reliability risk and different capacity resources during the winter season (see Appendix A), this report introduces and recommends the use of a Winter TRM in addition to the traditional Summer TRM. The Winter TRM is stated and represented by the following formula:

$$Winter\ TRM = \frac{TWC - WPL}{WPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TWC = Total Winter Capacity; and
WPL = Winter Peak Load.

Because winter peak loads are different than summer peak loads (lower for a summer peaking utility) and because winter generating capacity can have different operational characteristics than summer generating capacity, the Winter TRM can be higher than the Summer TRM. For example, the final, approved TRM from the 2015 Reserve Margin Study, which was essentially a Summer TRM, represented an increase in TRM from 15% to 16.25% due primarily to winter reliability issues. If planners had generated a Winter TRM from that study, the resulting reserve margin would have been 26%. ***However, such 26% Winter TRM would have represented both the same cost and the same level of reliability as its 16.25% Summer TRM equivalent*** – despite the appearances of being a “higher” reserve margin.

Reserve Margins are necessary because of uncertainties in operational conditions. The four primary uncertainties causing this need are:

1) **Weather**: The System’s “weather-normal” load forecasts are based on average weather conditions over the past 30+ years. If the weather is hotter than normal during warm seasons or colder than normal during cold seasons, the load will be higher. The System’s peak demand can be as much as 6.6% higher in a hot summer year and 22.0% higher in a cold winter year

than in an average year.[1] Drought conditions and temperature-related impacts on unit outputs can also significantly affect the System's load and capacity balance.

2) **Economic Growth**: It is difficult to project exactly how many new customers a utility will have or how much power existing customers will use from season to season. Based on historical projections and actual economic growth, peak demand may grow by [redacted] more than expected over a four to five-year period.[2]

3) **Unit Performance**: While the Operating Companies have a tremendous track record in keeping very low forced outage rates for the System, there have been occasions in the last ten years when more than 10% of the capacity of the system has been in a forced outage state concurrently.[3]

4) **Market Availability Risk**: The ability to obtain resources from the market when needed to address a short-term System resource adequacy issue is uncertain. In general, having access to resources in neighboring regions enhances a region's reliability due to load and resource diversity. However, the amount, cost, and deliverability of those resources are subject to the external region's resource-adequacy situation or transmission constraints at any given time. While a region can expect some level of support from its neighbors, each region must carry adequate reserves and manage its own reliability risks. Therefore, there is significant uncertainty regarding the availability of such external support when it is most needed.

While each of these four factors creates a need for capacity reserves on its own, confluence of all these risk factors poses considerable risk. Very high capacity reserves would be required to meet customers' load demands plus operating reserve requirements for all occurrences of such events. However, maintaining such high levels of capacity reserves comes at significant expense and may only eliminate very low probability events. A more appropriate approach to setting the TRM is to minimize the combined expected costs of maintaining reserve capacity, System costs, and customer costs associated with service interruptions, and adjust for the value at risk. A proper evaluation of these costs will result in the Economic Optimum Reserve Margin ("EORM"), properly adjusted for risk. However, that risk-adjusted EORM must also meet minimum reliability criteria thresholds. Common practice in the industry regarding this minimum reliability criteria threshold is to plan for a Loss of Load

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[1] See Figure A.4 in Appendix A.
[2] See Table I.3 in Section I.
[3] See Figure I.6 in Section I.

Expectation ("LOLE") of no greater than 0.1 days per year - or more commonly referred to in the industry as a one event in ten years criterion ("1:10 LOLE").

To understand and quantify the overlap of the four contributing factors to the need for reserve margins, a system dispatch model, Strategic Energy and Risk Valuation Model ("SERVM"), is utilized. SERVM evaluates the ability of the System's capacity resources to meet load obligations every hour in a year for thousands of combinations of weather, load forecast error, and unit performance scenarios. The model quantifies, in dollar cost, two components of reliability-related costs. These components are:

1. Production Costs, including the cost of generation as well as the cost of purchases, and
2. Reliability Costs, including the cost of customer outages (*i.e.,* expected unserved energy ("EUE") cost), emergency purchases, the cost of not meeting operating reserve requirements, and non-firm outage costs (i.e., the cost of calling demand response resources).

The Production Costs and Reliability Costs, determined by the SERVM model, are then compared to the Incremental Capacity Cost of new generation reserves. The analysis is performed on a range of planning reserve margins from 10% - 20%. With lower reserve margin levels, the import costs and Reliability Costs are high and vary widely, but the Incremental Capacity Cost and its associated generation cost are low. At higher reserve margin levels, the import costs and Reliability Costs are low, but the Incremental Capacity Cost and its associated generation cost are high. The objective of this study is to find the reserve margin where the sum of these costs is minimized (i.e. the minimum cost point), which is referred to as the EORM. The "U-curve" in Figure 1 shows the sum of Production Costs, Reliability Costs, and Incremental Capacity Costs across the range of reserve margin levels studied and demonstrates that the EORM occurs at a summer reserve margin of 15.25%. The figure represents the weighted average costs over all the load, weather, and outage draws simulated and is stated in terms of the traditional, summer-oriented reserve margin.[4]

[4] That is, stated in terms of summer capacity ratings and summer weather-normal peak demand.

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Figure 1. Traditional EORM U-Curve

However, Appendix A discusses in detail the winter reliability risks facing the System. To address those risks, the same analysis was performed from the perspective of a winter-oriented reserve margin.[5] The "U-Curve" in Figure 2 below shows the results of this analysis and demonstrates that the Winter EORM is 22.5%. Although the winter EORM appears to be much higher than the summer EORM, this difference is merely a function of how they were stated (*i.e.*, stated in summer terms vs. stated in winter terms as described above). The EORMs represent essentially the same level of cost and reliability and are therefore essentially equivalent.

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Figure 2. Winter EORM U-Curve

Finally, since winter is the driving factor behind the traditional results, thus leading to a need for a Winter TRM, an analysis was performed to determine what a Summer TRM would be assuming several of the key winter drivers were removed. Not all the winter-oriented drivers can be easily removed from the analysis, but Figure 3 below shows a summer-focused U-Curve with incremental cold weather outages and fuel constraints removed. The results of this analysis show that the EORM for the Summer TRM when these key winter drivers are removed is 14%.

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Figure 3. Summer EORM U-Curve

These three U-Curves and their associated analyses serve as the basis for determining a recommendation for the Winter and Summer TRM. Since, as described in Appendix A, winter is the constraining season for reliability on the System, the Winter TRM was considered first.

While the minimum cost of the winter U-Curve falls at 22.5%, the components that were evaluated to develop the U-Curve all have substantially different risk characteristics. The fixed costs of procuring capacity under a long-term PPA or building a new unit are relatively independent of the uncertainties that affect reliability. On the other hand, Production Costs and Reliability Costs can both vary significantly depending on weather, load forecast error, and unit performance.

The trade-off between static Incremental Capacity Costs and highly volatile Production Costs and Reliability Costs is difficult to measure. The expected value of Production Costs and Reliability Costs is the weighted average of all modeled simulations. For many mild weather or slow load growth scenarios, these Production and Reliability costs will be lower than the expected outcome. However, for more extreme cases, these Production and Reliability costs will be higher than the expected outcome, but lower in probability of occurrence. The significantly higher costs from these cases represent risk that should be considered when recommending a TRM because some of that risk may be mitigated at low incremental cost. The approach taken to mitigate the risk of potential high cost outcomes involves using a risk metric called Value at Risk ("VaR"). VaR is defined as the difference in cost at the expected value and at some specified confidence interval (e.g., the 80th percentile of risk). The VaR analysis looks at the incremental increase in expected cost to move from one reserve margin to the next reserve margin and compares that with the incremental decrease in VaR. The point at which the incremental increase in total system cost[6] equals the incremental decrease in VaR represents the EORM at that confidence interval (as opposed to the EORM at the weighted average). This analysis was performed at various confidence intervals ranging from the 80th confidence interval up to the 95th confidence interval using 0.25% reserve margin increments. As an example of the results of this analysis, the 80th confidence interval resulted in an EORM of 26.0%,[7] which represented an increase in expected case system costs from the 22.5% TRM of [redacted], but would reduce VaR (i.e., exposure to higher than expected future outcomes) on the System by [redacted].

This can be demonstrated graphically by developing the U-Curve at the 80th confidence interval instead of the expected cost. Figure 5 below shows that if you draw the U-Curve at the 80th confidence interval, the EORM is 26.0% instead of 22.5%. Therefore, a reserve margin a few percentage points higher than the expected case EORM benefits customers by eliminating many of the more expensive scenarios (thereby reducing the customers' exposure to cost risk) without significantly increasing expected costs. This outcome represents the risk-adjusted EORM at that confidence interval.

[6] Production Cost plus Reliability Cost plus Incremental Capacity Cost.

[7] Moving from 25.75% to 26.0% resulted in an incremental increase in weighted average costs roughly equal to the incremental decrease in VaR, while moving from 26.0% to 26.25% resulted in an increase in weighted costs that was greater than the decrease in VaR.

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Figure 5. 80% Confidence Interval U-Curve (Winter)

Additionally, the Reserve Margin Study contains reliability metrics such as LOLE. Common practice in the industry is to ensure that the TRM for planning purposes remains above an LOLE threshold of 0.1 days per year (or often referred to as a one in ten – 1:10 – year expectation of loss of load). LOLE has always been considered as part of the reserve margin studies; but in previous studies, the 1:10 LOLE threshold was below the EORM. In the 2018 Reserve Margin Study, the 1:10 LOLE threshold occurs above the EORM in both the summer and winter studies. It is not, however, greater than the VaR80 result. Therefore, in the 2018 Reserve Margin Study, the 1:10 LOLE threshold must be given greater consideration in the determination of the TRM than in previous studies. Figure 6 below shows the relationship between LOLE and reserve margin for the winter-focused study. The figure shows that the curve crosses the 1:10 LOLE threshold (i.e., an LOLE of 0.1 days per year) at [redacted] reserve margin. It is important that the TRM be above this 1:10 LOLE threshold to ensure an adequate level of reliability on the System. Otherwise, customers may be exposed to potential outages due to generation shortfalls more frequently than in other regions of the country. Results are similar in the traditional study.

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Figure 6. LOLE as a Function of Winter Reserve Margin

The 2018 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 25.25% 1:10 LOLE threshold to ensure an adequate level of reliability on the System;
2. A reserve margin of 26% represents the risk-adjusted EORM at the 80^{th} confidence interval (the 80^{th} percentile of risk – i.e., VaR80);
3. Compared to the 22.5% expected case EORM, a 26% risk-adjusted EORM reduces VaR at the 80^{th} confidence interval by [redacted] while only increasing expected cost by [redacted];
4. Compared to the 25.25% 1:10 LOLE threshold, a 26% risk-adjusted EORM reduces VaR at the 80^{th} confidence interval by [redacted] while only increasing expected cost by [redacted]; and

5. A 26% Winter TRM is consistent with results from the 2015 Reserve Margin Study,[8] confirming the results of that study.

For the long-term Summer TRM, in addition to consideration of the VaR results, consideration must also be given to the combined summer and winter LOLE. While the Summer-oriented U-Curve indicated an EORM of 14%, the VaR85 calculation resulted in a reserve margin of 16.75%. Therefore, a Summer TRM of up to 16.75% could be justified based on this case. However, LOLE must also be considered. If resources added to the System are available in both the winter and the summer, the LOLE will be in accordance to the curve in Figure 6. However, if the System's winter requirements are met with resources that are not available in summer, then a disconnect between the summer LOLE and the winter LOLE occurs. Therefore, when the combined LOLE for both summer and winter are considered, there is a floor for the Summer TRM that must be maintained to ensure that that the total combined summer and winter LOLE does not fall below the 1:10 LOLE threshold ("Summer TRM Floor"). Figure 7 below shows the 1:10 LOLE threshold Summer TRM Floor for various Winter TRM values.

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[8] In the 2015 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2016), the winter equivalent of the approved 16.25% TRM would have been 26%.

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Figure 7. Summer Target Reserve Margin Floor

[redacted]. Therefore, it is recommended that the current, approved 16.25% TRM (which is already stated in summer terms) remain in place as the Summer TRM.

For short-term planning (inside three years), a sensitivity has been performed which recognizes that there is typically less economic uncertainty in the nearer term (1-3 years out) than in the longer term (4 years out or greater). This sensitivity shows a difference in long-term reserve margin and short-term reserve margin of 0.5% is appropriate.

These recommendations are designed to provide guidance for resource planning decisions but should not be considered absolute targets. As explained throughout this report, various factors may justify decisions that result in reserve margins above or below the targets mentioned above such as the large size of capacity additions, the availability and price of market capacity, or economic changes.

RECOMMENDATIONS:

1. Implement Seasonal Planning with a Summer TRM and Winter TRM
2. Maintain current approved TRM of 16.25% as the Summer TRM
3. Implement a Winter TRM of 26%
4. Apply a short-term reserve margin with a 0.5% differential from the long-term reserve margins

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I. ASSUMPTIONS

The following sections of this report provide detailed discussions related to the input assumptions associated with the 2018 Reserve Margin Study.

A. Reliability Simulation Model

SERVM was used to calculate Production Costs and Reliability Costs for determining the EORM. These calculations were performed across a broad range of uncertainty risks in load forecast error, weather, unit availability, and performance of non-dispatchable, renewable resources.

Operating events are selected from actual operating history to determine generating unit availability. For each hour in every simulation, each unit will either be operating, on reserve shutdown, partially failed, completely failed, or on scheduled maintenance. The total capacity online and available for purchase is calculated and compared to the load to determine the associated EUE. Performing the random unit status draws for 100 iterations for every hour in the dataset results in average or expected case EUE.

SERVM perfectly matches load and generation, which is impossible to do in the real world. In actual practice, load would be curtailed in large blocks and would be off longer than necessary. If this reality could be incorporated into the model, the expected EUE would likely increase and the EORM would increase. As such, the results of the 2018 Reserve Margin Study should be considered conservative.

B. Study Year

[redacted] The representative year selected for this study was 2025.

C. Weather Years

The impact of weather on load was reflected by simulating the System using the 54 historical annual weather patterns from 1962 through 2015. These 54 patterns were then used to develop annual load shapes that would approximate what the load shape would be in the study year (2025) if the weather pattern matched that of one of the historical years. Two annual load shapes were developed for each of the 54 weather patterns. One assumed the first day of the year occurred on a Tuesday; the other assumed the first day of the year occurred on a Saturday. This was done to vary what day of the week extreme weather conditions were assumed to occur, since extreme weather can theoretically fall either on the weekend or on a peak day. These 108 datasets or “weather years” were given equal probability of occurrence.

The weather year load shapes were developed by using a neural net model to establish the relationship between the weather and load. The neural net was calibrated using weather and load data for the years 2010 through 2015 so that more recent customer usage patterns are reflected. The calibrated neural net was then used to construct the 108 weather year load shapes using the 54 historical weather patterns and two start days. The resulting loads are integrated hourly load shapes.

The temperature data used to develop these load shapes reflect the system weighted average temperature of several locations around the System’s footprint. Figure I.1 and Figure I.2 show the historical low winter and high summer temperatures experienced for the 54 weather years modeled.

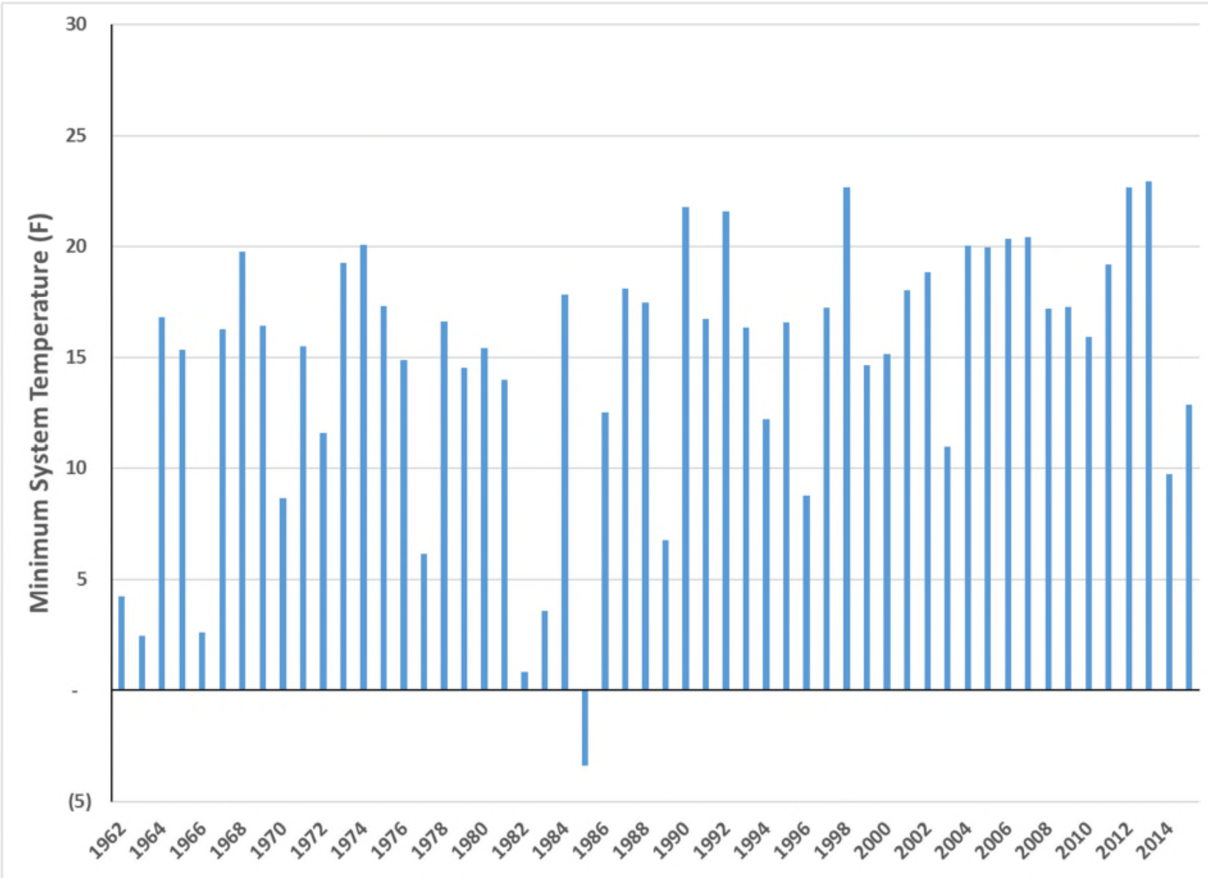

Figure I.1. Historical Low Winter Temperatures

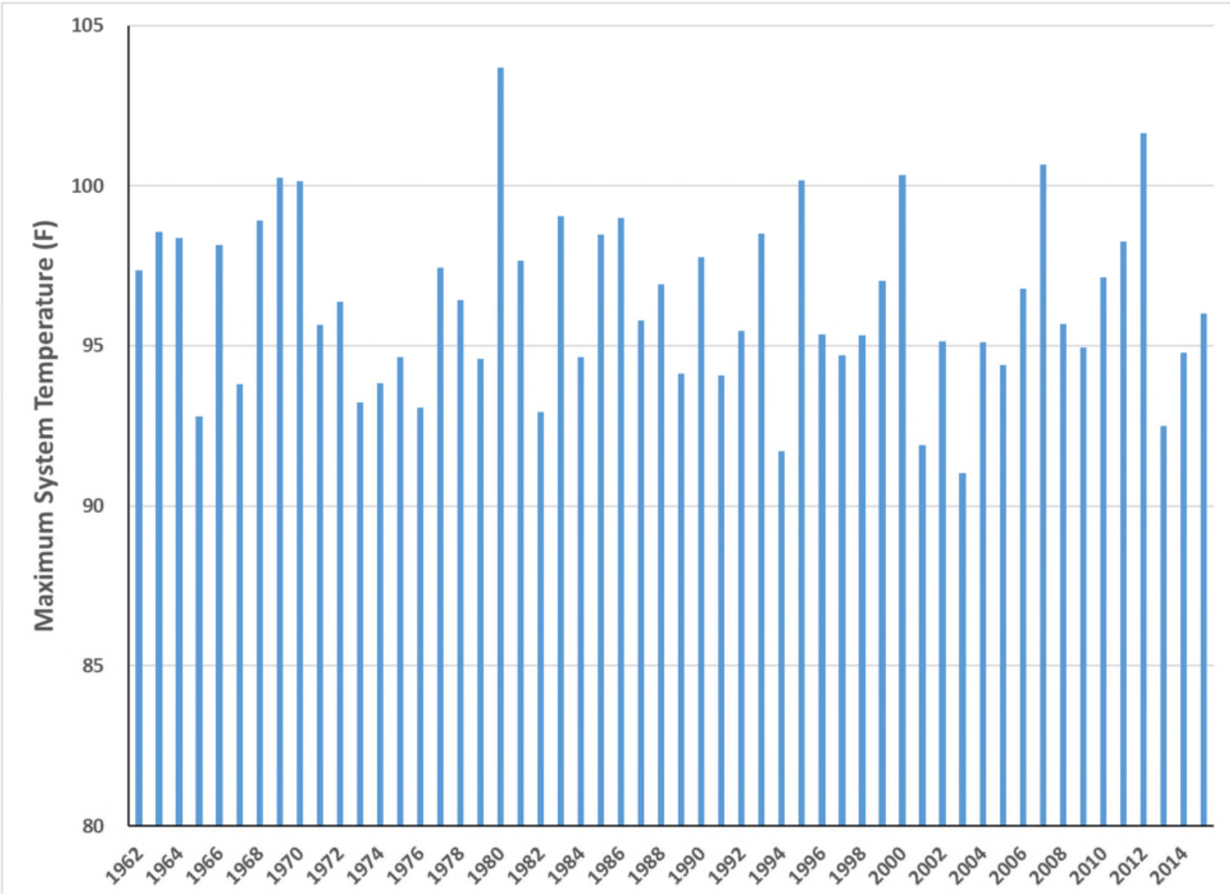

Figure I.2 Historical High Summer Temperatures

D. Market Modeling

The SERVM model allows the System to account for expected support from neighboring regions based on historical load diversity and unit performance diversity. Each weather year modeled uses the actual historical temperature and related load diversity for each region. The System is expected to be able to buy power from neighboring regions that do not typically peak in the same hour as the System if those neighboring regions have economic capacity available to purchase.

Resource adequacy planning requires modelers to build assumptions about the level of support available from neighboring regions. The actual operation of each unit for every neighboring region is modeled in the same way that resources are modeled within the System. Hydro, CTs, base load thermal resources, renewables, and demand response resource ("DRRs") are discretely modeled so that an accurate hourly market price forecast is produced. The CTs that have been modeled as marginal units to the System for purposes of developing the U-Curves are used to avoid purchasing from neighbors at high costs when they are either dispatching high cost resources or in scarcity situations.

The neighboring regions used in the simulation are summarized in Table I.1 (for Summer) and Table I.2 (for Winter) below. The reserve margins modeled in some regions were increased above their published targets to ensure those regions have a reasonable level of reliability (approximately equivalent to the 1:10 LOLE threshold). This is necessary since the regional model used in this analysis does not model a neighboring region's other interconnected regions (*i.e.*, the 2nd tier from the System) to account for the reliability benefit a neighboring region may obtain via purchases from its own neighboring regions. Without the adjustment, the reliability of these regions would be understated and would inappropriately underestimate the System's access to external markets.

Table I.1. Simulation Regions Summary for Summer

Region Name	Summer Reserve Margin Modeled (%)	Peak Load (MW)	Available Transfer Capability into Southern Company Systems (MW)	CBM[9] into Southern Company Systems (MW)
TVA	[redacted]	29425	796	300
Duke Energy Carolina	[redacted]	20433	180	350
SCEG	[redacted]	5736	148	0
Santee Cooper	[redacted]	4288	360	50
FPL	[redacted]	26145	20	100
Duke Energy FL	[redacted]	8796	18	50
JEA	[redacted]	2579	6	100
Power South	[redacted]	2139	300	-
OPC	[redacted]	5962	Unlimited	-
MEAG	[redacted]	2476	Unlimited	-
TAL	[redacted]	632	3	-
MISO	[redacted]	29014	1694	100

[9] Capacity Benefit Margin ("CBM") is a firm import reservation on the transmission system for use during emergencies.

Table I.2. Simulation Regions Summary for Winter

Region Name	Winter Reserve Margin Modeled (%)	Peak Load (MW)	Available Transfer Capability into Southern Company Systems(MW)	CBM into Southern Company Systems (MW)
TVA	[redacted]	30762	809	300
Duke Energy Carolina	[redacted]	21032	230	350
SCEG	[redacted]	5851	169	0
Santee Cooper	[redacted]	4743	416	50
FPL	[redacted]	23293	134	100
Duke Energy FL	[redacted]	10122	123	50
JEA	[redacted]	2782	44	100
Power South	[redacted]	2581	300	-
OPC	[redacted]	5717	Unlimited	-
MEAG	[redacted]	2240	Unlimited	-
TAL	[redacted]	634	18	-
MISO	[redacted]	25577	1688	100

The topology used for the simulations is in Figure I.3.

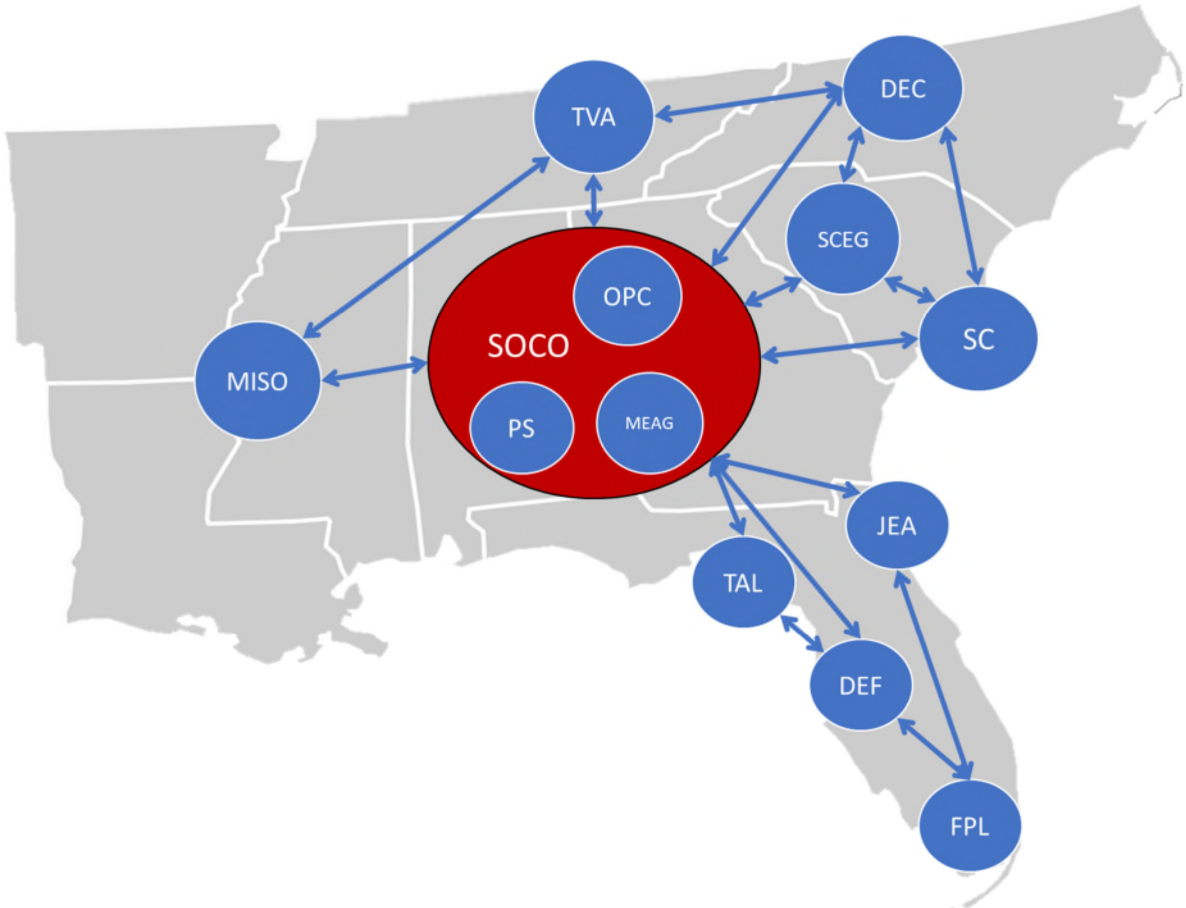

Figure I.3. Simulation Topology

It should be noted that the entirety of the MISO interconnection was not modeled. Rather, only those entities directly interconnected to Southern (Entergy and Cooperative Energy) were modeled. These entities were, however, jointly dispatched as a single entity to reflect operation within the MISO footprint.

Sales and purchase transactions are simulated between regions when the market price in one region is higher than an adjoining region and there is sufficient transfer capability. During extreme scenarios when loads are high, and many units are in a forced outage state, prices can rise substantially higher than the cost of a CT.

Scarcity pricing is the price markets experience when they are short on available capacity and is driven by several complex factors. While the scarcity pricing assumptions used in the Reserve Margin Study have been calibrated to historical scarcity market prices, those relationships may not always hold. During scarcity situations, the System will be subject to the market and, because of the importance of service reliability, is expected to make purchases even at prices well above [redacted] if they are reliably available.

A scarcity pricing curve, developed in conjunction with external consultant "ASTRAPE", used eight years (2010-2017) of historical market purchases to estimate the market purchase cost in scarcity scenarios and is shown in Figure I.4 below. Scarcity prices could rise as high as [redacted] if a region experiences a system emergency and shedding firm load is imminent. Scarcity prices are incremental (in addition to) generation costs.

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Figure I.4. Scarcity Pricing Curve

During emergency conditions, the System procures as much energy from the marketplace as possible and utilizes other peaking resources such as interruptible customers, voltage control, and emergency hydro. If the System is still short the necessary capacity to meet load plus operating reserves, CBM is utilized to obtain any additional energy that may be available. The System has CBM reservations on ties with TVA, Duke Energy Carolinas, Entergy, South Carolina Public Service Authority, Florida Power and Light, Duke Energy Florida, and JEA totaling 1,150 MW. This CBM capability was modeled and utilized as needed in the analysis.

Despite the load diversity associated with the regional modeling discussed above, the actual availability of purchases from other entities is not always as available as the SERVM model might indicate. Southern Company's Fleet Operations and Trading ("FOT") organization has advised that under extremely high summer load conditions, the availability of purchases in the marketplace is unlikely to exceed [redacted]. Likewise, under extremely high winter load conditions, the availability of purchases in the marketplace is unlikely to exceed [redacted]. These limitations exist for two reasons. First, during such extreme conditions, other market participants may also be experiencing conditions that approach the limits of their own system. Therefore, even though the model may show some available diversity between the regions, those entities may be unwilling to sell that capacity due to the risks and uncertainty on their own systems. Second, during such extreme conditions, there is often a high likelihood of transmission curtailments and so some capacity that may be available may not be deliverable to the system – even if there is transmission interface capability available. These limitations cannot be precisely modeled within SERVM, but a combination of both limits on sales price and hurdle rates between regions has been implemented as a means of addressing these issues.

Merchant capacity has been present in the southeastern United States for over 15 years, but the sporadic nature of its availability requires planners to be conservative in assumptions about its presence in the future. Merchant capacity may be purchased by other load serving entities in the region, may not have firm transmission, or may not have firm fuel supply. For these reasons, merchant capacity was assumed to be unavailable in the base case simulations.

E. Load Forecast Uncertainty

In addition to variation from normal weather, there remains uncertainty in the peak load projections when looking several years into the future. If load grows more quickly than expected, the reserve margin may not be sufficient unless that growth potential was properly considered in the reserve margin assumptions. Unexpected strength or weakness in the economy is a primary source of this load forecast error (“LFE”). An unforeseen change in electricity utilization and technology (*e.g.* heat pumps, electric transportation, and energy efficiency) can also be a source of LFE.

The LFE assumptions used in the 2018 Reserve Margin Study were updated in the fall of 2017. Load forecast uncertainty [redacted] into the future was estimated using [redacted] of historical data. The System has based its load forecast error assumptions on the [redacted] forecast growth of the economy and the assumption that there [redacted]. For the period [redacted], the forecasts of [redacted] for [redacted] into the future were compared with actual [redacted] to determine 21 economic forecast errors. The economic forecast errors were multiplied by [redacted] to determine 21 load forecast errors ranging from a maximum under-forecast error of [redacted] to a maximum over-forecast error of [redacted]. Each of the 21 LFEs has a [redacted] ([redacted]) chance of occurring. By combining and averaging similar LFEs, the 21 LFE points were converted to six LFE points as shown in the following table. For example, points 2 (LFE = [redacted]), 3 (LFE = [redacted]), and 4 (LFE = [redacted]) were combined and averaged to yield [redacted], and the combined probabilities were summed to achieve a combined probability of [redacted]). This was done to minimize the total number of runtime simulations that would be required while still considering an accurate distribution of LFE possibilities.

Table I.3. Load Forecast Error

	21 LFEs		6 LFEs	
	LFE	Probability	LFE	Probability
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]				
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		

Using this distribution, the minimum and maximum LFE values used in this study are [redacted] and [redacted] of the expected value, respectively.

F. Generating Unit Capacity Ratings

Unit ratings are traditionally established for both the summer and winter seasons. Summer ratings are generally established to correspond to output under 95ºF ambient temperatures. Table I.4 below shows the summer ratings associated with the nuclear, coal, and gas steam resources on the System. Only resources for which Alabama Power has ownership or contractual rights are specifically named. Other System resources are designated “SOCO Resource” in Table I.4.

Table I.4. Nuclear, Coal, and Gas Steam Unit Ratings

Unit Name	Unit Category	Peak Rating@95F (MW)
BARRY_4	Coal	362
BARRY_5	Coal	738.5
FARLEY_1	Nuclear	874
FARLEY_2	Nuclear	877
GASTON_5	Coal	832
GORGAS_10	Coal	718.7
MILLER_1	Coal	656.24
MILLER_2	Coal	651.74
MILLER_3	Coal	658.83
MILLER_4	Coal	658.83
SOCO RESOURCE	Coal	700

SOCO RESOURCE	Coal	700
SOCO RESOURCE	Coal	876
SOCO RESOURCE	Coal	876
SOCO RESOURCE	Nuclear	438.88
SOCO RESOURCE	Nuclear	442.38
SOCO RESOURCE	Coal	72.24
SOCO RESOURCE	Coal	72.24
SOCO RESOURCE	Coal	860
SOCO RESOURCE	Coal	75
SOCO RESOURCE	Coal	299
SOCO RESOURCE	Coal	475
SOCO RESOURCE	Coal	502
SOCO RESOURCE	Coal	502
SOCO RESOURCE	Coal	128.76
SOCO RESOURCE	Coal	134.55
SOCO RESOURCE	Coal	74.94
SOCO RESOURCE	Coal	74.94
SOCO RESOURCE	Nuclear	79
SOCO RESOURCE	Nuclear	83.47
SOCO RESOURCE	Nuclear	84.12
SOCO RESOURCE	Nuclear	102.89
SOCO RESOURCE	Nuclear	103
SOCO RESOURCE	Nuclear	41.54
SOCO RESOURCE	Nuclear	41.54
SOCO RESOURCE	Nuclear	538.2
SOCO RESOURCE	Nuclear	539.14
SOCO RESOURCE	Nuclear	503.61
SOCO RESOURCE	Nuclear	503.61
SOCO RESOURCE	Coal	459.03
SOCO RESOURCE	Coal	459.03
SOCO RESOURCE	Gas	350.5
SOCO RESOURCE	Gas	348.5

Winter ratings for nuclear and steam units are generally unchanged from the summer ratings. Ratings for CT and CC resources, however, can vary significantly depending upon the ambient temperature.

Official winter ratings for CT and CC resources are established to correspond to output at 40ºF ambient temperatures. Those ratings are shown in Table I.5 and Table I.6 below.

Table I.5. System CT Ratings

SYSTEM CT RATINGS		
Unit Name	**Peak Rating@95F (MW)**	**Peak Rating@40F (MW)**
AMEA_SYLAC_1	47.5	54.6
AMEA_SYLAC_2	47.5	54.6
Calhoun_CT_1	158	181.7
Calhoun_CT_2	158	181.7
Calhoun_CT_3	158	181.7
Calhoun_CT_4	158	181.7
GASTON_A	16	18.4
GREEN_CT_10	85	97.8
GREEN_CT_2	84	96.6
GREEN_CT_3	82	94.3
GREEN_CT_4	81	93.2
GREEN_CT_5	82	94.3
GREEN_CT_6	81	93.2
GREEN_CT_7	80	92
GREEN_CT_8	83	95.5
GREEN_CT_9	82	94.3
SOCO RESOURCE	149	171.4
SOCO RESOURCE	148	170.2
SOCO RESOURCE	14	16.1
SOCO RESOURCE	75.2	86.5
SOCO RESOURCE	74	85.1
SOCO RESOURCE	73.5	84.5
SOCO RESOURCE	74.9	86.1
SOCO RESOURCE	74	85.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1

SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	157.5	181.1
SOCO RESOURCE	36	41.4
SOCO RESOURCE	36	41.4
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	82.2	94.5
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	46	52.9
SOCO RESOURCE	150.9	173.6
SOCO RESOURCE	158.4	182.2
SOCO RESOURCE	149	171.4
SOCO RESOURCE	149	171.4
SOCO RESOURCE	148.9	171.2
SOCO RESOURCE	155	178.3
SOCO RESOURCE	154.6	177.7
SOCO RESOURCE	80	92
SOCO RESOURCE	80	92
SOCO RESOURCE	180	207
SOCO RESOURCE	185	212.8
SOCO RESOURCE	183	210.5
SOCO RESOURCE	183	210.5
SOCO RESOURCE	149	171.4

SOCO RESOURCE	146	167.9
SOCO RESOURCE	74.8	86
SOCO RESOURCE	74.7	85.9
SOCO RESOURCE	74.7	85.9
SOCO RESOURCE	55	63.3
SOCO RESOURCE	40	46
SOCO RESOURCE	15	17.3
SOCO RESOURCE	20.6	23.7
SOCO RESOURCE	19.6	22.5
SOCO RESOURCE	20.3	23.3
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	36.4	41.8
SOCO RESOURCE	35.5	40.8
SOCO RESOURCE	108	124.2
SOCO RESOURCE	49.9	57.4
SOCO RESOURCE	48.8	56.2
SOCO RESOURCE	68.3	78.5
SOCO RESOURCE	69.3	79.7
SOCO RESOURCE	27.1	31.1
SOCO RESOURCE	27.1	31.1
SOCO RESOURCE	25	28.8
SOCO RESOURCE	25.8	29.7
SOCO RESOURCE	25.6	29.4
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	26.1	30
SOCO RESOURCE	26.1	30
SOCO RESOURCE	3.2	3.7
SOCO RESOURCE	154	177.1
SOCO RESOURCE	100	115
SOCO RESOURCE	75	86.3
SOCO RESOURCE	32	36.8
SOCO RESOURCE	32	36.8
SOCO RESOURCE	29.9	34.4
SOCO RESOURCE	33	38
SOCO RESOURCE	41	47.2

SOCO RESOURCE	56	64.4
SOCO RESOURCE	49	56.4
SOCO RESOURCE	41	47.2
SOCO RESOURCE	54	62.1
SOCO RESOURCE	54	62.1

Table I.6. System CC Ratings

SYSTEM CC RATINGS		
Unit Name	**Peak Rating@95F (MW)**	**Peak Rating@40F (MW)**
BARRY_6	550	616
BARRY_7	557.1	624
SOCO RESOURCE	628	697.1
SOCO RESOURCE	567	629.4
SOCO RESOURCE	821	911.3
SOCO RESOURCE	823	913.5
SOCO RESOURCE	826	916.9
SOCO RESOURCE	660.6	733.3
SOCO RESOURCE	657.6	729.9
SOCO RESOURCE	885	885
SOCO RESOURCE	537.7	602.2
SOCO RESOURCE	556.8	623.6
SOCO RESOURCE	128.1	128.1
SOCO RESOURCE	140.1	140.1
SOCO RESOURCE	595	660.5
SOCO RESOURCE	242.5	269.2
SOCO RESOURCE	213.2	236.7
SOCO RESOURCE	679.4	754.1
SOCO RESOURCE	328	370.6
SOCO RESOURCE	577	640.5
SOCO RESOURCE	594.5	659.9
SOCO RESOURCE	379	420.7

Nevertheless, SERVM has features that can utilize the ambient temperature curves so that the actual output at the simulated system temperature can be modeled. Figure I.5 below shows the ambient temperature curves (on a per unit output basis) that were modeled within SERVM.[10]

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Figure I.5. Ambient Temperature Output Curves

G. Generating Unit Outage Rates

Generating units typically operate for a period, fail, are repaired, and then operate again. For example, a unit may run from 500 to 1,500 hours before it fails, take from 3 to 500 hours to repair, then run again for 500 to 1,500 hours.

Forced outage and maintenance outage data for the 2018 Reserve Margin Study consist of a series of observations of historical outage events from 2006-2016. This data is assembled into time-to-fail ("TTF") and time-to-repair ("TTR") distributions.

[10] One or two CCs have unique designs resulting in their own, unique ambient temperature output curve. Those curves are not shown on the chart.

Typical data for a unit might have up to five dozen entries in the TTF input data record, ranging from just a few hours to as many as 12,000 hours. Likewise, the typical data will contain a corresponding amount of entries in the TTR distribution, ranging from one to 2,500 hours. As the model processes chronologically, it will randomly choose a TTF duration from the first data record and then randomly choose a TTR duration. Individual unit operation, therefore, is a direct reflection of what has happened over approximately ten years. Since units are independent of each other, it is possible that many units can be down at once. An example of this type of input data for a steam unit is shown in Table I.7.

Table I.7. Steam Unit Sample Time to Fail and Time to Repair Data

Unit Name	Time-to-Fail (hours)	Time-to-Repair (hours)
Sample Plant	2747	4
	1839	5
	6710	11
	573	4
	333	5
	530	1
	233	2
	215	2
	752	1
	3710	6
	1338	2

Most steam units have their own specific outage history. However, the outage history of similar units has been combined to get a robust set of data from which to take random outage draws. Units with similar history and units for which no outage history was available were modeled using a similar reference unit.

Partial outages are modeled using the same rigorous approach that is used for full outages. A distribution is built for TTF events, TTR events, and the percentage derate. During the simulation, full outages and partial outages are tracked and randomly drawn.

The availability data for the System's "CC" units are modeled similarly to steam, with appropriate outage and derate TTF and TTR data. Additionally, in real-time operations, the supplemental modes (*i.e.,* full pressure ("FP") and power augmentation ("PA") of a CC) are dispatched separately from the base operating mode. The supplemental modes have a higher heat rate value and, therefore, tend to be dispatched during the same demand periods as CTs.

CT unit availability is generally driven by start failures. Once a CT starts, it is rare that it fails during run-time. Within SERVM, all CT availability data has been modeled as a startup probability with TTR data based on real observations. CT data include startup probabilities ranging from 85% to 99%. Repair data range from 8 to 93 entries in the TTR input data records with values ranging from less than an hour to nearly 100 hours.

To further refine outage rates, SERVM allows these historical TTF and TTR values to be scaled in aggregate to achieve an expected outage rate. The historical TTF and TTR values were thus scaled to get outage rates expected for each unit class (see Table I.8 below).

As the model progresses chronologically, it randomly chooses a time to fail duration from the TTF data record and then randomly chooses TTR duration (for CTs, the failure is determined by a probability draw when the startup is initiated and then the TTR is chosen randomly). Individual unit operation, therefore, is a direct reflection of what has happened over the selected sample years of data. The resulting forced outage rates, ratios of failed hours to operating hours, or ratios of failed hours to total hours are thus outputs of the model rather than inputs. Because forced outage rates are an output of the model, there can be minor differences in the resulting EFOR from case to case, but with sufficient outage draw iterations in the simulation, the resulting EFOR should converge to an expected value. The table below shows the resulting EFOR from one of the simulated runs, excluding any impacts from cold weather-related outages, which should be approximately the same in all cases.

Table I.8. Approximate EFOR by Unit Class

Unit Class	EFOR (%)
Nuclear	1.9
Coal	2.9
Gas Steam	2.2

Combined Cycle	1.6
CTs	5.2
Total System	2.7

The SERVM simulation randomly selects failure events and operating events for each unit. For every hour, certain units will be operating, and other units will be in a failure state. To ensure the model predicts these events accurately, a comparison was made of the simulated outage probability to the actual outage probability. This comparison, shown in Figure I.6, confirms that the modeled outage rate is consistent with the historical outage rate and indicates that the impact of outage events is adequately modeled.

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Figure I.6. Unplanned Outage Probability

H. Incremental Cold Weather Outages

The discussion of outage data in the previous sections describes the "base" level of outage expected across the year. However, history has demonstrated that under extremely cold conditions, outage rates can increase as coal piles and pipes begin to freeze, as oil thickens to the point that it will not flow sufficiently to operate a facility, or as instrumentation and controls or other plant equipment begin to freeze. These situations do not materialize until weather conditions are extreme, and these extreme weather conditions are less common. When they occur, however, the outage impacts can be significant and can increase in an exponential manner. Historically, these incremental outages have materialized at system weighted temperatures roughly [redacted] and below. However, efforts to minimize these impacts have been made in recent years and implemented across the system. Based on these efforts, it is expected that performance improvements will be such that these incremental outages will not begin to materialize until approximately [redacted], as shown in Figure I.7 below. The figure shows (a) a trend of historical unit outages under various cold weather conditions (see Appendix A for more detailed explanation of this trend), (b) an incremental trend of these outages assuming a [redacted] underlying system "EFOR", and (c) a trend representing the assumptions used in this study that includes expected performance improvements.

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Figure I.7. Cold Weather Outage Assumptions

I. Planned Outage Patterns

Planned outages occur most often in the shoulder months because the demand on the units to run during the peak demand months does not allow for a lot of down time. Traditionally, planned maintenance events are not scheduled during either the summer months (June-September) or January and February unless it cannot otherwise be avoided or for oil units in noncompliance zones. While maintenance schedules are generated annually for the upcoming 5 years, the Reserve Margin

Study is looking more generically and therefore allows the model to schedule maintenance around anticipated peak load periods. The model schedules these maintenance outages during low demand periods in such a way that the maintenance outage rate achieves the desired rate for the year. In general, this results in planned maintenance modeled relatively consistent with actual practice. Figure I.8 below shows the likelihood that a resource will be assigned a planned outage in any given month.

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Figure I.8. Planned Outage Probability by Month

J. Commitment and Operating Reserves

Resources are committed to match current operating practices. Each week during a simulation, the loads for each hour of the week are examined and the optimum dispatch is set to meet the system peak load while maintaining the required operating reserves for every hour. The optimum dispatch takes into consideration which units are available, the minimum uptimes and downtimes for each unit, the startup costs and times for each unit, and the necessary required operating reserves. Operating reserves are required by the Southern Balancing Authority, which is the entity responsible for balancing load and generation in the region, to meet North American Electric Reliability Corporation

("NERC") Reliability Standards. The Southern Balancing Authority provides guidance regarding the amount of operating reserves that should be modeled based on their operational requirements. That guidance included a total operating reserve requirement of [redacted], broken down according to the following components:

- Regulating Reserves: [redacted] of nominal solar capacity or [redacted]
- Contingency Reserve-Spinning: [redacted]
- Contingency Reserve-Supplemental (or Non-Spinning): [redacted]

In addition, the Southern Balancing Authority's guidance established a firm load curtailment threshold of [redacted] of total operating reserves, meaning that firm load should be curtailed to maintain a minimum total operating reserve requirement of [redacted]. However, SERVM cannot model a fixed MW operating reserve value for the purposes of firm load curtailment. Rather, SERVM can be configured to curtail firm load to maintain Regulating Reserves plus Contingency Reserve-Spinning. Therefore, only 496MW of Contingency Reserve-Spinning was modeled so that the sum of Regulating Reserve and Contingency Reserve-Spinning did not exceed [redacted]. The remaining [redacted] of the [redacted] of operating reserves was modeled as Contingency Reserve-Supplemental, such that the final modeled operating reserves were as follows:

- Regulating Reserves: [redacted]
- Contingency Reserve-Spinning: [redacted]
- Contingency Reserve-Supplemental (or Non-Spinning): [redacted].

K. Dispatch Order

Generation resources are generally dispatched economically based upon dispatch prices. The exceptions include energy-limited resources and non-dispatchable resources. Energy-limited resources, such as hydro and pumped storage hydro, are typically scheduled based on availability of water and expected system costs. Non-dispatchable resources, such as solar and wind vary with the weather. Therefore, the dispatchable resources are typically optimized around the output of these other non-dispatchable or pre-scheduled resources. Demand response resources either self-curtail based upon price (*e.g.*, Real Time Pricing programs) or are called whenever the system reaches certain reliability conditions (such as a system alert). Figure I.9 below shows the dispatch stack order for the dispatchable resources modeled in the 2018 Reserve Margin Study. The chart excludes the energy-limited, non-dispatchable, and demand response resources.

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Figure I.9. System Dispatch Stack

L. Dispatchers' Peak Load Estimate Error

The dispatchers' peak load estimate error consists of three separate time periods, including day ahead, four-hour ahead, and hour ahead. The amount of dispatcher's peak load estimate error modeled for each of these time periods was based on actual, historical forecast error data for the years 2012 through 2015. The table below shows the resulting mean and standard deviation that served as the basis for the modeled dispatcher's peak load estimate error.

Table I.9. Historical Dispatcher's Peak Load Forecast Error

	Day Ahead Mean	Day Ahead Std Dev	4-Hour Mean	4-Hour Std Dev	Hour Ahead Mean	Hour Ahead Std Dev
January	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

M. System-Owned Conventional Hydro Generation

System-owned hydro capacity of 2,400 MW (projected for the year 2025) was divided into two components:

1) Scheduled Hydro
2) Emergency or "Unloaded" Hydro

This study includes 54 different hydro scenarios that are matched with the 54 weather scenarios. The 54 scenarios chosen are based on the past 54 years (1962-2015) of weather and hydro data. For each of the scenarios, scheduled hydro capacity is modeled based on actual history.

The optimal dispatch of hydro resources is not solely an economic decision. Planners must consider river flow requirements and impacts on other reservoirs in the same river system. During drought conditions, it is rare that the full capacity of all hydro resources would be dispatched at the same time. The total hydro capacity that is not used as part of the daily schedule would be available as emergency hydro. Only in cases of extreme need is the emergency hydro capacity called upon to operate. Also, the emergency hydro block is only available for a small number of events per year. To model this within SERVM, the emergency hydro block is tied to a flex energy account to reflect the limited availability of this emergency hydro energy. If the emergency hydro capacity is needed to meet load during emergencies, the model will pull energy from this account. If the energy account becomes depleted, the capacity will not be available during subsequent emergencies.

Figure I.10 depicts the monthly energy produced by the two components of System-owned hydro generation in a representative year, 1998. The figure illustrates the typical distribution of available hydro energy across the months of the year.

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Figure I.10. Hydro Energy Availability (1998 Example Data)

As with the weather data, the availability of hydro energy can vary year to year. Figure I.11 below illustrates the total available scheduled hydro energies from the past 54 weather years (1962-2015).

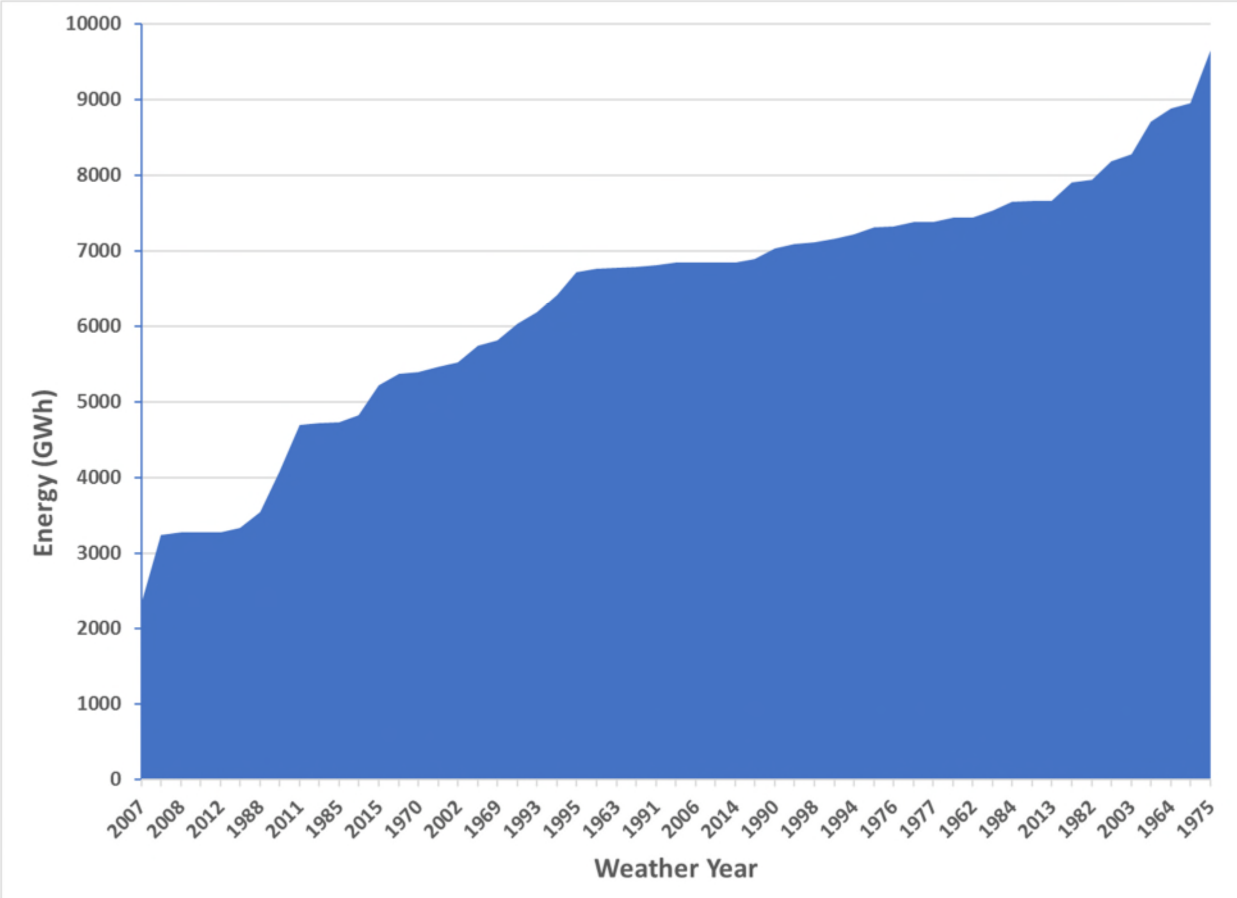

Figure I.11. Annual Scheduled Hydro Energies

N. SEPA Conventional Hydro

The Southeastern Power Administration ("SEPA") conventional hydro is less flexible in its operation than the System-owned hydro. The System has a contractual right to an allocation of the SEPA hydro capacity. Within SERVM, SEPA conventional hydro is modeled as a standard hydro unit with minimum daily dispatches. As currently modeled, the System is entitled to 477 MW taken over four hours per weekday, with a minimum daily schedule of 637.8 MWh and a maximum monthly energy allocation of 14.162 GWh.

O. Pumped Storage Hydro

Pumped storage hydro is a resource that is designed to pump water to an elevated reservoir using energy at off-peak periods when prices are low, and to generate electricity by releasing that water at times when prices are high. The dispatch of pumped storage is not simply a reliability decision, although the reservoir should always be kept at a level where energy will be available for emergency conditions. The System has a total of 540 MW of pumped storage resources spread across two different locations (Wallace Dam and Rocky Mountain Pumped Storage Facility). The Rocky Mountain Pumped Storage Facility is co-owned with Oglethorpe Power Corporation (“OPC”).

P. Demand Response Resources

Approximately [redacted] of DRR capacity (contract value) is included in the analysis for the summer, and approximately [redacted] are included for the winter. These DRR include such programs as Interruptible Service (“IS”), Real-Time Pricing (“RTP”), Direct Load Control (“DLC”), Conservation Voltage Reduction (“CVR”), and Stand-by Generation (“SBG”). The model reflects both the seasonal availability as well as the contract constraints (*e.g.,* hours per year, days per week, and hours per day) for these energy-limited resources, so there is no need to adjust the contracts in the model by multiplying by Incremental Capacity Equivalent (“ICE”) factors. In general, ICE factors represent the worth of load management resources, such as an interruptible service contract, relative to the value of incremental generating capacity that can be added to the system.

These resources occupy specific positions in the dispatch order as established by an assumed dispatch price. The position in dispatch affects their ability to reduce EUE and alters the frequency with which they are called. Some of these resources, such as RTP, are called based on economics and have an assumed dispatch price associated with them that is consistent with the expectation of the market prices that would result in self-curtailment by the customer. Others are called only to avoid EUE, and their assumed dispatch price is used mainly to establish the priority in which these programs are called. That priority is established based on how operations would anticipate them to be called in a generation shortfall event and would result in CVR being called first, followed by DLC, then IS, and finally SBG. Within the IS category, the programs are split into three blocks so that not all contracts are called simultaneously.

Q. Renewable Resources

NOTE: Except as otherwise stated, the Southern Companies maintain the right to use the electricity and all environmental attributes associated with all renewable projects discussed in this report for the benefit of its customers. This includes the right to use the electricity and the environmental attributes for the service of customers, as well as the right to sell environmental attributes, separately or bundled with electricity, to third parties.

The amount of renewable resources modeled for the System includes

- Biomass: 248 MW
- Landfill Gas: 43 MW
- Solar: 3,144 MW, and
- Wind: 588 MW.[11]

Biomass and landfill gas resources were modeled like other resources with a fixed output level based on their nominal capacity. However, the output of wind and solar resources are dependent upon weather conditions and location. Except for a few of the wind resources on the System that have been contracted based on a fixed hour-by-hour schedule, the output of the wind and solar resources varies moment-by-moment, hour-by-hour, and year-by-year. These wind and solar resources have been modeled with 8,760-hour profiles that are consistent with each of the 54 weather years as well as consistent with their location. Because the profiles included in the model for these resources reflect the hour-over-hour and year-over-year variances in output, there is no need to adjust the resources by multiplying by ICE factors.

R. Natural Gas Availability

Natural Gas operates in accordance to the Gas Day (*i.e.*, 9AM-9AM), whereas electricity operates according to the Electric Day (*i.e.*, Midnight to Midnight). Firm gas transportation is procured for the fleet's gas-fired units, but 24-hour Gas Day coverage is not procured for every plant. The amounts to be procured are generally driven by the System's Fuel Policy. Although case-specific situations may

[11] Wind capacity listed includes certain fixed delivery wind energy contracts. The total wind capacity shown includes the amounts delivered from these contracts coincident with the System peak.

allow for deviations from the Fuel Policy, for purposes of the 2018 Reserve Margin Study, all facilities under control of the Operating Companies were modeled in compliance with the Fuel Policy unless they had no contractual rights to dictate the amount of gas transportation to be purchased for the facility.

SERVM models both firm and non-firm gas transportation and its associated availability. During periods of high demand for natural gas, the System is limited to firm transportation contracts since interruptible transportation is not available. This constraint has been incorporated into the modeling process. The model begins phasing out interruptible transportation (*i.e.*, it starts becoming unavailable) when the daily minimum system weighted temperature falls below [redacted] or when the daily maximum system weighted temperatures rises above [redacted]. When the daily minimum temperature falls below [redacted] or the daily maximum temperature rises above [redacted], no interruptible transportation is available for that Gas Day. Figure I.12 below illustrates the availability of interruptible transportation as modeled within SERVM.

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Figure I.12. Interruptible Gas Transportation Availability Model

S. Oil Availability

For dual-fuel (gas/oil) and oil-fired units, oil availability is dependent upon onsite storage. Storage capacity is limited, so when gas is not available, onsite oil supply will deplete quickly. This may limit a unit's availability if refilling efforts cannot keep up with usage.

T. Capacity Cost

For the type of analysis performed in this study where the objective is to balance the cost of the incremental capacity with the reliability benefits achieved by that capacity addition, it is necessary that the capacity considered represents a true reliability addition, not an addition for both reliability and energy economics. As such, simple-cycle CT technologies are the appropriate resources to be utilized for the evaluation. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral cost associated with that resource. Since both summer and winter evaluations were performed in the 2018 Reserve Margin Study, economic carrying costs based on both summer and winter performance characteristics were needed. The CT cost model is a green-field site of four dual-fueled units each with a 95°F ambient temperature summer rating of [redacted] MW and a 40°F ambient temperature winter rating of [redacted] MW, resulting in a summer performance economic carrying cost in 2025 dollars of [redacted] and a winter performance economic carrying cost in 2025 dollars of [redacted].

U. Cost of Expected Unserved Energy

To estimate the cost of EUE, Freeman, Sullivan & Company conducted an outage cost survey of Georgia Power Company and Mississippi Power Company customers in 2011.[12] This survey was conducted among the following four customer classes:

- Residential;
- Commercial (below 1 MW average demand);
- Industrial (below 1 MW average demand); and
- Large business (commercial and industrial customers above 1 MW average demand).

[12] While the survey only included customers from two Operating Companies, the results are considered appropriate for all Operating Companies, and so the cost of the survey was shared by all Operating Companies.

The cost of EUE (in 2012$) for these four customer classes is shown in Table I.10 for both the summer and winter periods. The cost of EUE was then adjusted by the customer weighting factor representing recent relative weighting of customers in that class. The results of that weighting are also shown.

Table I.10. EUE Cost

EUE COST IN 2012 $					
Outage Scenario	**Residential ($/kWh)**	**Commercial ($/kWh)**	**Industrial ($/kWh)**	**Large Business ($/kWh)**	**Weighted Average ($/kWh)**
Weighting Factor (%)	[redacted]	[redacted]	[redacted]	[redacted]	
1 hour, no warning, summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contribution to Weighted Average	[redacted]	[redacted]	[redacted]	[redacted]	
1 hour, no warning, winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contribution to Weighted Average	[redacted]	[redacted]	[redacted]	[redacted]	

These estimated weighted costs of EUE were then escalated to 2025 dollars for use in the 2018 Reserve Margin Study. The result was a Value of Loss Load ("VOLL") of [redacted] for summer and [redacted] for winter.

II. SIMULATION PROCEDURE

A. Case Specification

The simulations performed for the 2018 Reserve Margin Study were designed to estimate System generation reliability across a wide range of weather conditions, LFEs, and reserve margins. Eleven discrete reserve margin levels were simulated to calculate the expected costs over a broad range of scenarios. Load shapes corresponding to the 108 weather datasets (54 weather years, each with Tuesday and Saturday start days), were run in combination with varying LFEs. Weather years were paired such that loads, hydro scenarios and renewable profiles were consistent. The simulation variables were as depicted in Table II.1.

Table II.1. SERVM Case Variables

Weather and Hydro Years	Summer/Winter Reserve Margins	LFEs
1962-2015	10%/17.0%	[redacted]
	11%/18.2%	[redacted]
	12%/19.5%	[redacted]
	13%/20.7%	[redacted]
	14%/21.9%	[redacted]
	15%/23.1%	[redacted]
	16%/24.4%	
	17%/25.6%	
	18%/26.8%	
	19%/28.0%	
	20%/29.3%	

The winter reserve margins are the equivalent of their summer counterparts. Thus, the winter reserve margins are not listed in whole percentage point increments.

Positive LFE represents an over forecasted load, meaning actual load was less than forecasted load.

Without accounting for load forecast uncertainty, the total number of combinations for the analysis would be 54 × 2 × 11, or 1,188 cases. Considering the six load forecast points yields 7,128 cases (54 × 2 × 11 × 6 cases). Each of these cases were then evaluated 100 different times, each with a different set of random forced outage draws on the generating resources, yielding 712,800 production cost simulations (54 x 2 x 11 x 6 x 100 cases). Estimating EUE for each of the 712,800 simulations provides sufficient data for regression analysis of other combinations not specifically simulated. This set of simulations was performed for both the traditional analysis as well as the winter focus analysis and the summer focus analysis.

B. Probabilities of Occurrence for Input Variables

As discussed in the previous sections, the chronological variable inputs into the model are used to represent appropriate ranges of data. For example, the weather years selected to exemplify load variations due to temperature changes represent 54 years of historical data. This is also true for the hydro patterns and solar profiles developed. Each, however were modeled twice – once with a Saturday start and once with a Tuesday start – resulting in 108 different weather/hydro datasets. The implementation of load forecast uncertainty into the evaluation is representative of the potential (supported by historical information) LFEs when considering the future. Each of the six forecast errors has its own probability of occurrence that is related to the probability of error in forecasted economic indicators. For each reserve margin studied, the combined set of input variables results in 648 individual cases having their own designated probability of occurrence to be used in the probabilistic evaluation. Table II.2 depicts the probabilities assigned to each of these variables and the resulting probability for each case. This total case probability is determined by combining the probabilities of the determinant variables. The weather years and start days all have equal probability of occurrence.

Table II.2. Simulation Case Probability

LFE	LFE Probability	Weather/Hydro Probability	Start Days Probability	Total Case Probability
[redacted]	0.0952	0.018519	0.5	0.000882
[redacted]	0.1429	0.018519	0.5	0.001323
[redacted]	0.2381	0.018519	0.5	0.002205
[redacted]	0.3333	0.018519	0.5	0.003086
[redacted]	0.1429	0.018519	0.5	0.001323
[redacted]	0.0476	0.018519	0.5	0.000441

C. Reliability Model Simulations

SERVM incorporates Monte Carlo techniques to conduct generation reliability simulations. Monte Carlo analysis uses a random number generator to determine generating unit availability for the System. For each iteration, the model simulations will randomly select the state of a generating unit as fully operational, partially failed, or completely failed and determine if the system experiences loss of load and associated EUE.

For each of the 648 cases, each hour of the year was modeled with 100 draws from the distribution of generating unit outage and duration data to determine if there exists a deficiency of generating capacity to meet load demand. The 100 iterations were averaged together to establish a case-specific result. A deficiency of generating capacity in any hour is recorded as a loss of load hour. The magnitude of the outage during that hour is measured by EUE. The EUE is then aggregated by month and multiplied by the respective value of lost load for that month to determine the EUE cost. The monthly EUE costs are then summed together for the year to determine EUE cost for that case. The case EUE cost is then multiplied by the probability of occurrence for that case and the results for all cases are summed to determine the expected value of EUE cost for that reserve margin simulation. This process is repeated to determine the expected value of generation costs, import costs, emergency purchase (or sales) costs, the cost of non-firm outages (i.e., demand response costs), and costs associated with non-spinning reserve shortfalls.

For each reserve margin simulation, the expected value of generation costs and import costs are then summed together to establish "Production Cost". Likewise, the expected value of emergency purchases (or sales), demand response costs, costs associated with non-spinning reserve shortfalls, and EUE costs are summed together to establish "Reliability Cost." Figure II.1 shows the formula used for calculating EUE. Other components are calculated similarly.

$$\boldsymbol{Expected\,Y = \sum_{i=1}^{n}(Y_i * \; Probability_i)}$$

where

$$\boldsymbol{Y = EUE\ and,}$$

$$\boldsymbol{n = number\ of\ cases}$$

Figure II.1 Variable Calculation Formula

Table II.3 thru Table II.6 provide an example of implementing the formula for a sample data set containing the 10 worst Reliability Cost cases. Table II.3 shows the Reliability Cost components with their per unit weighted costs. Table II.4 shows the probability weighting of the Total Reliability Cost. For illustrative purposes, all calculations are for a 17% summer reserve margin simulation.

Table II.3. Sample Calculation Top 10 Worst Reliability Costs at 17% Summer Reserves

Data Set	Emergency Purchases (MWh)	Emergency Purchases Cost ($/MWH)	EUE (MWh)	EUE Cost ($/MWH)	Demand Response Calls (MWh)	Weighted DR Cost ($/MWH)	Loss of Non-Spin Reserve (MWh)	Loss of Non-Spin Cost ($/MWH)
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table II.4. Worst Reliability Costs Weighted Probability

Data Set	Probability	Emergency Purchases ($M)	EUE ($M)	Demand Response Calls ($M)	Loss of Non-Spin ($M)	Total Reliability Cost ($M)	Weighted Reliability Cost ($M)
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A similar calculation is performed for the components of Production Cost as demonstrated in Table II.5 and Table II.6 for the same 10 cases shown above.

Table II.5. Production Cost Components for Sample Data Set

Data Set	Generation Costs ($M)	Purchases (MWh)	Purchase Cost ($/MWH)
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]

Table II.6. Production Cost Weighted Probability

Data Set	Probability	Generation Costs ($M)	Purchase Cost ($M)	Total Production Cost ($M)	Weighted Total Production Cost ($M)
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

By applying regression analysis to the expected values of Production Cost and Reliability Cost, a curve summarizing the Production Cost, Reliability Cost, and Incremental Capacity Cost as a function of reserve margin was developed. These results are discussed in detail in the next section.

III. BASE CASE RESULTS

A. Traditional Study Results

In theory, the economic optimum reserve margin, or the EORM, should be the reserve margin that results in the minimum total system costs. The three components of total system costs (Production Cost, Reliability Cost, and Incremental Capacity Cost) that vary across reserve margin levels were added together to create an aggregate total system cost curve (the "U-Curve"). The minimum point on the resultant U-Curve, which is at 15.25%, represents the EORM. This graph is presented below.

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Figure III.1. Traditional EORM U-Curve

B. Winter-Focused Reserve Margin Results

The 2015 Reserve Margin Study identified several drivers associated with issues during extreme cold weather. Those drivers included:

a. the narrowing of summer and winter weather-normal peak loads,
b. the distribution of peak loads relative to the norm,
c. cold-weather-related unit outages,
d. the penetration of solar resources, and
e. increased reliance on natural gas.

In addition to these same drivers, the 2018 Reserve Margin Study identified an additional constraint – the availability of market purchases (see Assumptions section of this report). Because all these drivers will impact winter reliability, it has been determined that even though the System remains a summer peaking utility for the time being, the System's primary reliability risk is in the winter, resulting in the need for a Winter TRM. Appendix A addresses this need for a Winter TRM more thoroughly, but as an example of this need, Figure III.2 below shows seasonal EUE by reserve margin. As indicated by the chart, at low reserve margins, summer and winter have relatively equal expectations of EUE – with summer being higher at very low reserve margins. However, as reserve margins increase, the expectation of EUE in the summer reduces drastically. Similarly, the expectation of EUE in the winter falls as reserve margin increases, but not as drastically and even at 20% reserve margin, there is still a significant expectation of potential loss of load.

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Figure III.2. Seasonal EUE by Reserve Margin

To address this winter reliability risk, a Winter TRM is necessary. Therefore, a separate analysis was performed where the focus of the study was on a winter reserve margin. Traditionally, the reserve margin is stated in summer terms – that is, stated in terms of summer peak loads and summer resource ratings. For example, the reserve margins in Figure III.2 above are all stated in summer terms. The traditional analysis is performed by developing the 108 historical weather load shapes in such a way as to ensure the average summer peak load from all 108 load shapes equals the summer peak demand forecast for the study year. To perform the winter focused reserve margin analysis, the 108 load shapes were adjusted such that the average of the winter peak loads equaled the winter peak demand forecast. The results of the study were then stated in winter reserve margin terms rather than summer reserve margin terms (i.e., stated in terms of winter peak loads and winter resource ratings). The minimum point on the resulting U-Curve was established as 22.5% as shown in the graph below.

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Figure III.3. Winter EORM U-Curve

It is important to recognize that while the EORM from the winter U-Curve occurs at a reserve margin that appears to be significantly higher than the EORM from the traditional, summer-oriented U-Curve, the EORM from the two cases represent similar levels of reliability and cost for the same underlying system. Each study contains a full year of hourly production cost simulations which inherently reflect 8,760 reserve margin levels. Therefore, the difference in absolute value (22.5% versus 15.25%) primarily a function of stated terms, with the summer EORM being stated in terms of summer capacity ratings and the summer weather-normal peak load and the winter EORM being stated in terms of winter capacity ratings and winter weather-normal peak load.

C. Summer-Focused Reserve Margin Results

Given that the System's primary reliability risk is in the winter, it is possible to determine a summer-focused reserve margin without consideration of some of the key winter drivers, specifically without the incremental cold-weather generation outages or the natural gas fuel constraints. The idea behind this analysis is to determine the corresponding Summer TRM once the Winter TRM has been established. The following graph shows that a summer-focused EORM without those key drivers would be 14%.

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Figure III.4. Summer EORM U-Curve (Without Key Winter Drivers)

D. Risk Analysis

The winter-focused combination of Production Cost, Reliability Cost, and Incremental Capacity Cost results in a EORM of 22.5%. However, since Production Cost and Reliability Cost are highly dependent on the selected scenario, consideration of only the EORM does not give a complete picture. Figure III.5 illustrates the volatility in Production Cost and Reliability Cost exposure. In scenarios in which load grows faster than expected, temperatures are higher than expected, or unit performance is poorer than expected, the cost exposure can be much higher than the expected case.

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Figure III.5. Production and Reliability Cost Distributions for Winter Reserve Margins

Zooming in on the most extreme cases shown in Figure III.5 for each reserve margin further highlights the risk in carrying low reserves. Figure III.6 shows the exposure for the top 10% of all cases as ranked by Production Costs and EUE cost exposure. The most extreme case simulated at a 17% winter reserve margin shows over [redacted] per year in total exposure, while the most extreme case at a 26% reserve margin is approximately [redacted].

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Figure III.6. Top 10% Distribution for Winter Reserve Margins

To more appropriately perform a comparison between highly volatile Production Costs and Reliability Costs and fixed Incremental Capacity Cost, thus protecting against the potential for an extremely high cost outcome, additional risk analyses should be performed. In the casualty insurance business, customers have the option of paying an insurance premium to cover the impact of a catastrophic loss. In this example, the annual insurance premium is higher than the cost of the loss times its probability. Customers and regulators are comfortable with paying an amount greater than the average loss because it makes the payments fixed. In the same way, utilities can procure capacity at fixed rates slightly above the EORM to prevent the possibility of certain high cost outcomes. The approach taken to evaluate the risk of these potential high cost outcomes and thus determine how much of an "insurance premium" to pay is to use a risk metric called Value at Risk ("VaR").

VaR is defined as the difference in cost at the expected value and the cost at some specified confidence interval (e.g., the 85th percentile of risk). The VaR accounts for the customers' exposure to higher costs above normal conditions. The VaR analysis looks at the incremental increase in expected cost to move from one reserve margin to the next reserve margin and compares that with the incremental decrease in VaR. So long as the incremental increase in expected cost is less than the incremental decrease in VaR, the premium (*i.e.*, the increased expected cost) is justifiable to protect against the potential high cost outcomes. The point at which the incremental increase in cost equals the incremental decrease in VaR represents the EORM at that confidence interval (as opposed to the EORM at the weighted average).

The table below illustrates the VaR at the 80th (VaR80), 85th (VaR85), 90th (VaR90), and 95th (VaR95) percentiles of confidence for a range of winter reserve margin targets.

Table III.1. Value at Risk

Reserve Margin	Expected Cost (M$)	VaR80 (M$)	VaR85 (M$)	VaR90 (M$)	VaR95 (M$)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For the 80th percentile of risk (VaR80), the incremental increase in expected cost roughly equals the incremental decrease in VaR80 when moving from 25.75% reserve margin to 26% reserve margin. At this point, the incremental increase in cost is [redacted]; and the decrease in VaR80, or decrease in customers' exposure to higher cost outcomes, is [redacted]. Moving from 26% to 26.25% results in an increase in expected costs [redacted] that is greater than the decrease in VaR80 [redacted]. Thus, 26% represents the EORM at the 80th percentile of risk. Compared to the expected case TRM of 22.5%, a 26.0% reserve margin reduces the VaR80 exposure by [redacted] while only increasing the expected case cost by [redacted]. Higher confidence intervals were also examined. At the 85th percentile of risk, it would be justifiable to establish a reserve margin of 26.25%. At the 90th percentile of risk, it would be justifiable to establish a reserve margin of 27.25%. Likewise, at the 95th percentile of risk, it would be justifiable to establish a reserve margin of 28.5%. However, the increased expected cost for these three confidence intervals are [redacted], [redacted], and [redacted], respectively. While justifiable from a cost/risk reduction perspective, the absolute increase in expected cost suggests use of the 80th or 85th confidence interval as there is a much bigger jump in expected costs moving to the 90th confidence interval.

Another way to explain and understand the risk analysis used in this study is to realize that the VaR analysis essentially establishes the EORM at the specified confidence interval. In other words, the Operating Companies calculate the EORM at the expected value of cost. However, because of risk, it would be justifiable to calculate the EORM at, for example, the 80th percentile of cost. This is precisely what the Var80 analysis accomplishes – the economic balance between cost and risk. Figure III.7 below shows the total cost (Production Cost plus Reliability Cost plus Incremental Capacity Cost) at the 80th confidence interval. The resulting "U-Curve" confirms that the EORM at the 80th confidence interval is 26.0% - that is, 26.0% is the risk-adjusted EORM at the 80th confidence interval.

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Figure III.7 80% Confidence Interval U-Curve

E. Loss of Load Expectation

Some regions throughout the country utilize Loss of Load Expectation (LOLE) as their primary resource adequacy reliability metric, while others either do not consider it or consider it as a secondary metric to the EORM. LOLE is the probabilistic count of the number of days in the study year in which the system experiences firm load shed of any duration. This metric does not measure the magnitude of the event and is relatively sensitive to several input assumptions. The most common business practice for those who use this metric is an LOLE value of 0.1 days per year, which is sometimes referred to as a one day in ten years (1:10 LOLE) reliability criterion. An LOLE of 0.1 days per year presumes there is a 10% probability of a loss of load due to generation shortfall in any one year or an expectation that there would only be one loss of load event every 10 years.

Historically for the Southern Company System, this 1:10 LOLE threshold has occurred at reserve margins below the EORM. Thus, the primary focus has historically been on the risk-adjusted EORM to establish the TRM. However, as the Company continues to incorporate new reliability risks in its reliability modeling, more recent analyses have indicated that the LOLE for the System is much higher than previously expected. Thus, the reserve margin necessary to maintain the 1:10 LOLE threshold is also higher. Figure III.8 below illustrates how this metric looks for the System over the range of reserve margins studied for the 2018 Reserve Margin Study as compared to the 2012 and 2015 reserve margin studies. The reserve margins are shown in summer terms since neither the 2012 nor the 2015 studies included a winter analysis.

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Figure III.8. Loss of Load Expectation by Summer Reserve Margin

At its current approved Target Reserve Margin of 16.25% (which is equivalent to a 24.7% winter reserve margin), the System has an LOLE of [redacted] or an expectation of one event in [redacted], which is below the 1:10 LOLE threshold. As indicated by the chart, to achieve a 1:10 LOLE threshold would require a 17% Summer TRM. Figure III.8 was shown in summer terms as a comparison to previous, traditional studies. However, since the increase in observed LOLE is associated with winter reliability issues, it is necessary to review these metrics as generated by the winter focus study. Figure III.9 below shows the LOLE for the winter reserve margins evaluated.

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Figure III.9 LOLE for Winter Reserve Margins

At the winter EORM of 22.5%, the LOLE is [redacted] or an expectation of one event every [redacted]. To achieve a 1:10 LOLE threshold would require a winter reserve margin of 25.25%. In both the traditional study and the winter focus study, the 1:10 LOLE threshold is above EORM but still below the VaR85 reserve margin. At the VaR85 reserve margin of 26.25%, the LOLE expectation is one event every [redacted].

It would not be appropriate to establish a TRM that has an expected level of reliability that is lower than common industry practice. For this reason, consideration of the 1:10 LOLE threshold as a determinant in making a final TRM recommendation is necessary and appropriate.

F. Total System Cost Components

The total system cost is the sum of three components:

1) The annual carrying cost of CTs added for reserve margin (Incremental Capacity Cost);
2) Reliability Costs; and
3) Production Cost.

Following is a discussion of each component.

1) Annual Carrying Costs of CTs

The incremental annual capacity carrying cost of the added capacity at any given reserve margin is determined by multiplying the incremental CT kW capacity by its economic carrying cost. For the traditional and summer focus studies, this cost was determined using summer performance values, resulting in a carrying cost of [redacted]. To achieve an increase of one percent reserve margin in the summer studies requires the addition of [redacted] or [redacted] in carrying cost. For the winter focus study, the cost was determined using winter performance values, resulting in a carrying cost of [redacted]. To achieve an increase of one percent reserve margin in the winter focus study requires the addition of [redacted] or [redacted] in carrying cost. As more CTs are added to achieve a higher reserve margin, these carrying costs accumulate with the megawatts added. This is represented in Figure III.10 (for the winter focus study), which shows a linear increase in costs when graphed as a function of reserve margin.

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Figure III.10. Incremental Capacity Cost (Winter Focus)

2) Reliability Costs

Reliability Costs are the sum of the cost of EUE, the cost of any shortfalls in meeting required operating reserves, the cost of emergency purchases (or sales), and cost of demand response calls. The cost of EUE is determined by multiplying the amounts of EUE in MWh at each reserve level created in the analysis by the assumed cost of EUE in $/MWh (with EUE in the winter being multiplied by the winter cost of outage and EUE in all other months multiplied by the summer cost of outage). The cost of meeting shortfalls in spinning and regulating reserves are included in the cost of EUE as the model curtails load to maintain these requirements. The cost of meeting supplemental (*i.e.*, non-spin) reserve requirements is determined by the scarcity price at the time of the shortfall. The cost of demand response calls is determined by the presumed dispatch price for each demand response program as established by the Operating Companies. Figure III.11 illustrates Reliability Cost as a function of winter reserve margin.

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Figure III.11. Reliability Cost

3) Production Cost

Production Costs include the variable operating costs of units plus the cost of any purchases with neighboring regions less the cost of any sales with neighboring regions. Production costs at each reserve margin level can be seen in Figure III.12.

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Figure III.12. Production Cost

As expected, Reliability Costs and Production Costs decrease as reserve margin increases. Conversely, their costs increase as the reserve margin is reduced.

IV. SENSITIVITY ANALYSES

The basis of the data for unit performance, weather, load forecast error, hydro availability, market prices, and other inputs is from historical information. Other data such as market availability is based on forecasted information. While the broad range of scenarios analyzed capture extreme events and market prices, there remains risk that conditions could occur in the future that extend beyond the range of what is contemplated in the base case model. Each of the following sensitivities were modeled to examine their impact on both the EORM and the 1:10 LOLE threshold.

In addition to the sensitivities related to the uncertainties above, a sensitivity was modeled to determine how the optimum reserve margin would change if the load forecast uncertainty was reduced to determine a short-term reserve margin target.

A. Capacity Price

Capacity price has an inverse impact on the EORM. The EORM calculation assumes the addition of a reliability resource (i.e., a CT) that has little or no energy value. This ensures a fair comparison of capital cost against Production Cost and Reliability Cost. At lower capacity prices, it is economically justifiable to have a higher TRM. Conversely, if capacity prices are higher, the EORM will be lower. The capacity price used in the 2018 Reserve Margin Study represents the economic carrying cost of a CT. The capacity price sensitivity examined a range of capacity costs from values as low as the Budget 2018 Retail Capacity Price Forecast ("RCPF") to values higher than the economic carrying cost of a dual fuel CT. Figure IV.1 shows how capacity costs across these ranges affect the Winter EORM. For example, at the 2025 RCPF of [redacted], the Winter EORM moved from 22.5% to more than 29%. Capacity price does not impact the 1:10 LOLE threshold.

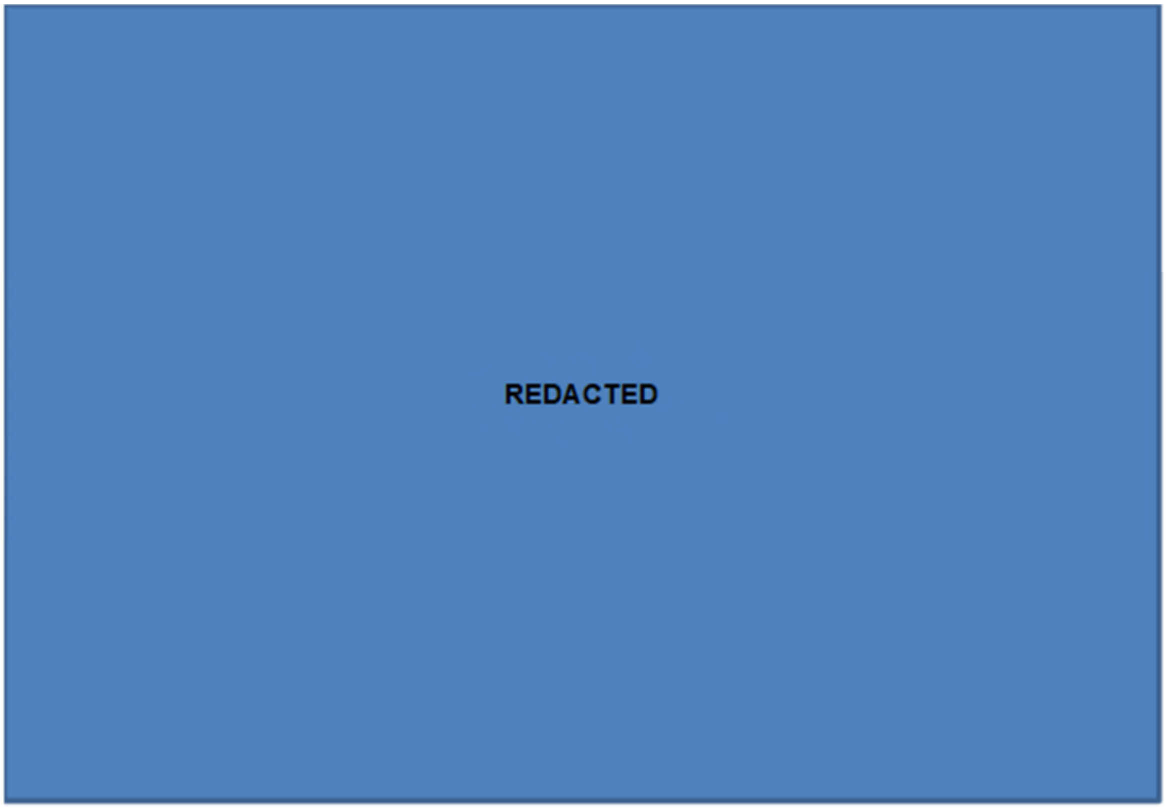

Figure IV.1. EORM as a Function of Capacity Price

B. Minimal Cost of EUE

Two cost-of-EUE sensitives were evaluated. The first was a minimum value assuming only impacts from residential class customers. This resulted in a cost of EUE of approximately [redacted] of outage (in 2025$). The Winter EORM for this sensitivity moved from 22.5% to 20.5%. There was no change in the 1:10 LOLE threshold.

C. Publicly Available Cost of EUE

The second cost of EUE sensitivity was one that was developed based on publicly available cost of EUE data. Using the Interruption Cost Estimate Calculator, developed by Nexant and funded by Lawrence Berkeley National Laboratory and the Department of Energy and is publicly available at http://icecalculator.com, a cost of EUE for the System was estimated to be approximately [redacted]. The Winter EORM for this sensitivity moved from 22.5% to 23.0%. There was no change in the 1:10 LOLE threshold.

D. No Cold Weather Outage Improvements

As indicated in the Section I, Assumptions, the cold weather outage assumptions used in the 2018 Reserve Margin Study incorporated substantial unit performance improvements over historical actual performance. This sensitivity assumes those performance improvements are not realized and the future cold-weather outage performance is consistent with historical performance. The Winter EORM for this sensitivity did not significantly change from the base case. However, the 1:10 LOLE threshold moved from 25.25% to 25.75%.

E. Higher Scarcity Price Curve

For the 2018 Reserve Margin Study, the scarcity price curve was updated, resulting in significantly lower scarcity price curves. Because the scarcity price curve is based on recent historical market conditions, it is possible that the current assumptions for the scarcity price curve are biased low due to the general high levels of current reserve margins throughout the neighboring regions. As the actual reserve margins in the neighboring regions all decrease towards their respective target reserve margins, it is anticipated that scarcity prices could return to levels seen previously. This sensitivity assumes that the scarcity price curve would be more consistent with that used in prior reserve margin studies (2012 and 2015). The Winter EORM for this sensitivity moved from 22.5% to 23.75%. The 1:10 LOLE threshold moved from 25.25% to 24.75%.

F. 50% Reduced Transmission

For this sensitivity, transmission capabilities with neighboring regions were reduced by 50%. This resulted in an increase in the Winter EORM from 22.5% to 23%. It also resulted in an increase in the 1:10 LOLE threshold from 25.25% to 25.5%.

G. 50% Increased Transmission

For this sensitivity, transmission capabilities with neighboring regions were increased by 50%. The results of the 50% increased transmission scenario showed no change in the Winter EORM. However, the 1:10 LOLE threshold decreased from 25.25% to 25%.

It should be noted that both the 50% Reduced Transmission sensitivity and 50% Increased Transmission sensitivity only resulted in marginal changes in reliability (with little or no change in economics). Together, this indicates that transmission interface capability with the interconnected regions is adequate from a reliability standpoint.

H. 50% Higher Base EFOR

For this sensitivity, base level unit outages were increased by 50%. Incremental cold-weather outages were not impacted by the sensitivity. The 50% higher unit outage scenario resulted in an increase in the Winter EORM from 22.5% to 23.25%. Similarly, the 1:10 LOLE threshold increased from 25.25% to 26.75%.

I. 50% Lower Base EFOR

For this sensitivity, base level unit outages were decreased by 50%. Incremental cold-weather outages were not impacted by the sensitivity. The 50% lower unit outage scenario resulted in a reduction in the Winter EORM from 22.5% to 21.55%. Similarly, the 1:10 LOLE threshold decreased from 25.25% to 23.75%.

Summary of Sensitivity Analyses

Figure IV.2 below shows a graphical representation of the results of all the sensitivity analyses (i.e., Sensitivities A through I). For Sensitivity A (capacity costs), two results are shown, representing capacity prices associated with the Budget 2018 RCPF (A) and ½ of the economic carrying cost of a CT (A'). The chart shows both Winter EORM and the 1:10 LOLE threshold. Together, they demonstrate that the sensitivity analyses validate the base case results of the 2018 Reserve Margin Study and indicate that its results are robust against those sensitivities.

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Figure IV.2. Summary of Winter Sensitivity Results

Short-Term Load Forecast Error

For this sensitivity, short-term load forecast errors were used. This sensitivity resulted in the Winter EORM decreasing from 22.5% to 22.0%, reflecting a difference in long-term and short-term reserve margins of 0.5%. The short-term load forecast errors used are in the following table.

Table IV.1. Short-Term Load Forecast Error

SHORT-TERM LOAD FORECAST ERROR	
LFE	**Probability**
[redacted]	0.0833
[redacted]	0.1250
[redacted]	0.25
[redacted]	0.2917
[redacted]	0.1667
[redacted]	0.0833

V. CONCLUSION

Winter reliability issues drive the 2018 Reserve Margin Study results. Therefore, a Winter TRM is required to ensure the appropriate level of resource adequacy.[13] However, it is necessary to establish both a Winter TRM and a Summer TRM for several reasons. It is possible that capacity needs can be driven by either season and should be considered when adding new capacity. In addition, there is the potential that, over time, changes in rate structures, demand-side programs, and other initiatives could alter the dynamics of the system such that the primary risk shifts between seasons. Therefore, it is recommended, that a TRM be set for both seasons, with the Winter TRM established based on the results of the winter focused study and the Summer TRM established based on the summer focused study with 1:10 LOLE threshold considerations for both as discussed below.

Winter Target Reserve Margin

The 2018 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 1:10 LOLE threshold of 25.25% to ensure an adequate level of reliability on the System;
2. A reserve margin of 26% represents the risk-adjusted EORM at the 80th confidence interval (the 80th percentile of risk – i.e., VaR80);
3. Compared to the 22.5% expected case EORM, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by [redacted] while only increasing expected cost by [redacted];
4. Compared to the 25.25% 1:10 LOLE threshold, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by [redacted] while only increasing expected cost by [redacted]; and
5. A 26% Winter TRM is consistent with results from the 2015 Reserve Margin Study,[14] confirming the results of that study.

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[13] See Appendix A for further justification of the need for a Winter TRM.

[14] In the 2015 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2016), the winter equivalent of the approved 16.25% TRM would have been 26%.

Summer Target Reserve Margin

The Summer EORM from the summer focus study is 14.0%, with the VaR85 reserve margin being 18%. However, the Summer TRM cannot be determined without consideration of the Winter TRM. If the System is meeting its 26% Winter TRM requirement with resources that provide year-round capacity, the summer reserve margin will generally be at or above 17.3%. This means that the Winter TRM is driving the System reliability, even though the next capacity need for one or more of the Operating Companies may still be in the summer. However, in the event seasonal resources (such as winter-only resources) are made available, it may be possible to lower the Summer TRM below 17.3% - so long as the combined annual reliability remains above the 1:10 LOLE threshold. The following graph demonstrates the minimum acceptable Summer TRM as a function of Winter TRM. For a Winter TRM of 26%, the minimum acceptable Summer TRM is [redacted].

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Figure V.1. Minimum Acceptable Summer Target Reserve Margins

The recommendation, therefore, is to establish a Winter TRM of 26%, while maintaining the currently approved 16.25% as the Summer TRM. This recommendation would apply for studies looking out four or more years. For studies looking inside a three-year window, the recommended Winter and Summer TRM are 25.5% and 15.75% respectively, reflecting a 0.5% reduction from the long-term TRM resulting from the difference between the long-term forecast error and the short-term forecast error.

These recommendations are designed to provide guidance for resource planning decisions but should not be considered absolute requirements. The large size of capacity additions, the availability and price of market capacity (as indicated by the Capacity Cost sensitivity), or economic changes may justify decisions that result in reserve margins above these targets.

Components of the Target Reserve Margin

Figure V.2 shows the contribution of each of the components of uncertainty (weather, market risk, unit performance, load forecast error, and fuel supply) toward the overall required Winter TRM of 26%.

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Figure V.2. Economic Components of Winter TRM

Likewise, Figure V.3 shows how each of the components contribute to the minimum Summer TRM of 16.25%.

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Figure V.3. Economic Components of Summer TRM

The 26% Winter Target Reserve Margin recommended for the System reflects the results of the economic study and a variety of other information available and is extremely important in planning to best meet customer needs and provide for a more reliable generation system. The 16.25% minimum Summer TRM is necessary to ensure the combined summer and winter reserve margins remain at about the 1:10 LOLE Threshold.

Appendix A – Examining the Need for a Winter Target Reserve Margin

A. Background

The last time that the "System" experienced an outage due to a generation shortfall was on January 17, 1977 – a winter reliability event. Since that time, the System has delivered reliable, low-cost generation even through some of the coldest weather on record during the mid-1980s. The ability to maintain reliable service during those extreme periods was primarily because the System's summer peaks were significantly higher than the System's winter peaks in that era as demonstrated in the figure below.

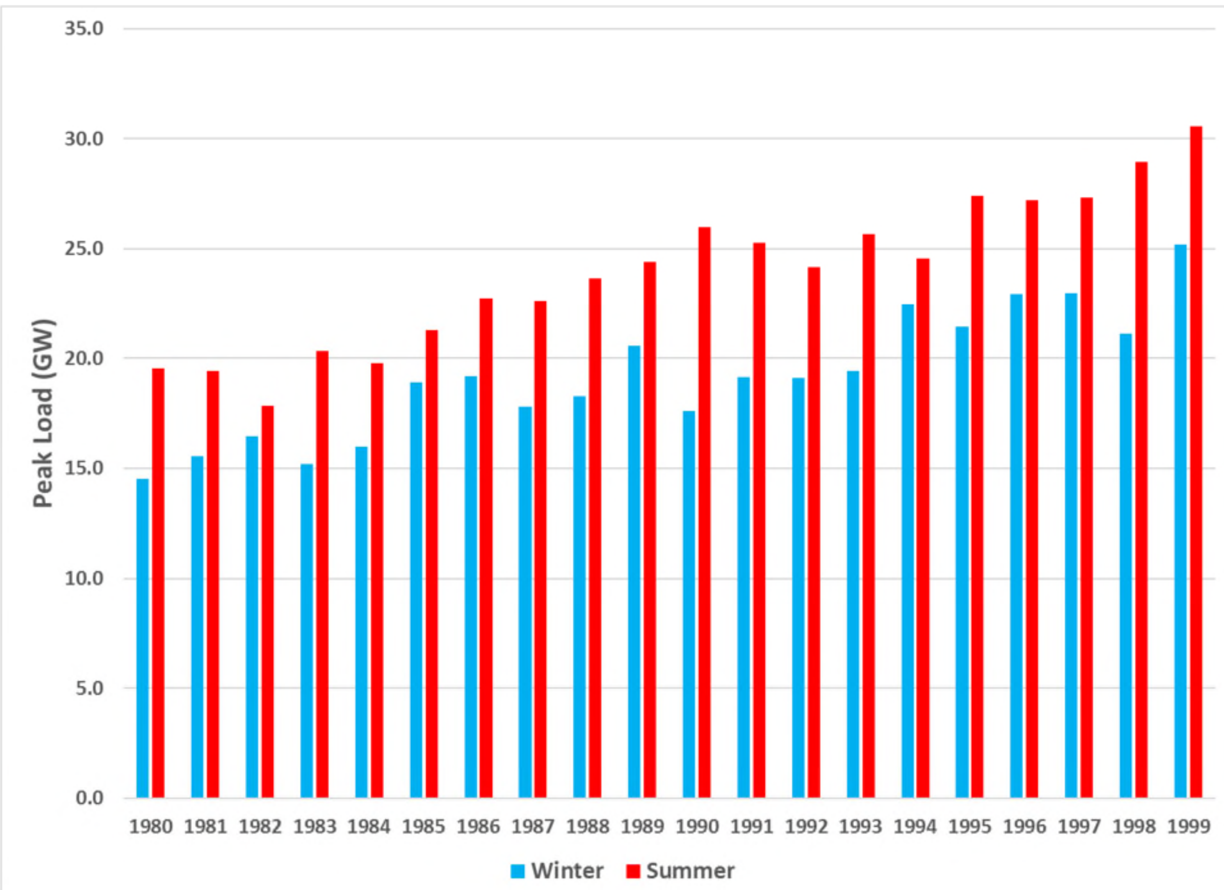

Figure A. 1. Summer and Winter Historical Peak Demands

In addition to being primarily summer peaking, during the 1990s and 2000s, the System only experienced one year, 1996, where system-weighted temperature fell below 10ºF. During that same stretch of time, customer technology and behavior began to change. Emphasis on energy efficiency and summer demand response programs began to alter the dynamics of customer response to extreme summer and winter temperatures. That evolving response (at least as it relates to winter) was never observed due to the absence of the extreme cold-weather events. The streak without extreme cold weather ended in January 2014 with the Polar Vortex event when system-weighted temperatures reached 9ºF. The chart below shows the minimum system-weighted temperatures observed on the System between 1962 and 2015.

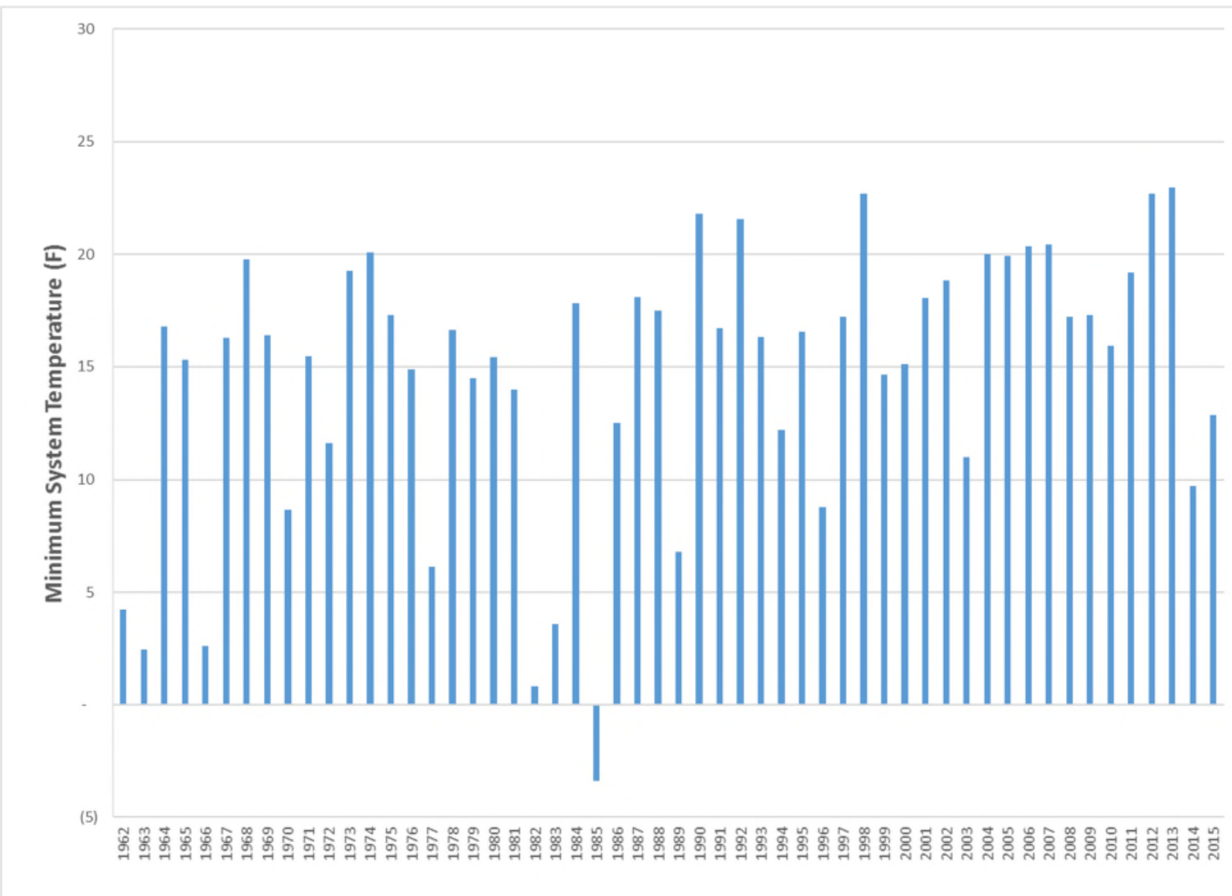

Figure A. 2. Historical Minimum System Temperatures

It was the 2014 Polar Vortex event in which this change in load response was first observed. At that time, the System had a reserve margin of approximately [redacted], representing approximately [redacted] of more reserves in 2014 than what was required by the short-term TRM at that time of 13.5%. Without these additional reserves the System would have experienced a significant loss of load event during the 2014 Polar Vortex, which could have been as large as [redacted]. Similarly, the System may have also experienced such an event in the winter of 2015 but for the approximately [redacted] plus of reserves above the 13.5% short-term TRM. Between 2014 and 2018, there have been 23 winter-weather-related operations advisories,[15] including 20 times when a Conservative System Operations ("CSO") Watch[16] advisory was issued, once when the System declared Alert Level 1A,[17] once when the System declared Alert Level EEA1, and once when the System declared Alert Level EEA2.[18] By comparison, during the same period, there have been only three CSO events directly related to summer peak load conditions.

Even prior to the Polar Vortex event of 2014, operations personnel began expressing concern over reliability risks during the winter peak period. On August 16, 2011, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) issued a report and guidance document expressing the need to be concerned with winter reliability issues. That report, *Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices*,[19] was developed after a February 2, 2011 event in ERCOT in which approximately 1.3 million electric customers did not have service during the winter peak demand of that day. The Operating Companies, however, had already been performing such assessments beginning in 2007 for the 2008 Winter Peak Period. Those assessments first began indicating the potential for a reliability concern when the assessment performed in 2009 for the 2010 winter peak noted "Possible Gas Scheduling Restrictions" as a challenge. The list of challenges expanded each year forward from that point.

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[15] Based upon report generated by Southern Balancing Authority Area.
[16] A CSO is issued when there is an expectation of high load that warrants extreme caution during operations.
[17] A Southern Balancing Authority Area internal "alert" that occurs just prior to NERC Alert Level EEA1.
[18] EEA1 and EEA2 are system alert levels defined by the North American Electric Reliability Corporation ("NERC").
[19] Document accessible from NERC at https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Generating_Unit_Winter_Weather_Readiness_final.pdf.

Currently, there are six primary determinants (discussed in more detail below) that have been identified as key drivers affecting the winter reliability risk concerns on the System, including

- the narrowing of summer and winter weather-normal peak loads,
- the distribution of peak loads relative to the norm,
- cold-weather-related unit outages,
- the penetration of solar resources,
- increased reliance on natural gas, and
- market purchase availability.

Prior to the 2015 Reserve Margin Study, [20] most of these drivers were unobserved and unmodeled in the reliability planning model. The 2015 Reserve Margin Study made a first attempt at modeling these drivers, resulting in an increase in Target Reserve Margin from 15% to 16.25%. Since the 2015 Reserve Margin Study, planners have continued efforts to refine both the modeling assumptions and the modeling techniques surrounding these drivers. In the process, it has become evident that the most effective way to plan for and manage these reliability risks is to establish a Winter Target Reserve Margin.

B. Key Drivers

The six primary drivers affecting the winter reliability risk issue are discussed in the following sections.

B.1 Narrowing of Summer and Winter Weather-Normal Peak Loads

On a weather-normal basis, the System remains a summer peaking utility. However, over the course of the last 10-15 years, the gap between the weather-normal summer peak load and the weather-normal winter peak load has narrowed. Figure A. 3 below shows the one-year ahead forecasted peak loads since 2006 as well as the Budget 2018 forward-looking longer-term forecast. The graph shows how the gap between the summer and winter weather-normal forecasted peak loads has narrowed since 2006 from greater than [redacted] to less than [redacted].

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[20] An Economic Study of the System Planning Reserve Margin for the Southern Company System, January 2016.

Because the gap between these peaks has narrowed – and are likely to remain closer in the future – the System has less flexibility to handle any significant variations in seasonal reliability such as those described in the remaining sections below. Therefore, it becomes necessary to examine System performance in the winter independently from the summer through a Winter Target Reserve Margin.

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Figure A. 3. Historical Forecasted Weather Normal Peak Loads

B.2 Distribution of Peak Loads Relative to the Norm

As discussed in the Background section above, customer load response has changed such that response to abnormal weather conditions in the winter is more volatile than the summer. One of the primary purposes of the TRM is to have the resources necessary to handle these abnormal weather conditions. In both the summer and the winter, there is a probability distribution around the forecasted weather-normal peak load. This distribution is determined by the expectation of non-weather-normal conditions, represented within SERVM[21] by the 108 modeled load shapes for the 54 historical weather years. Figure A. 4 below shows the distribution of the modeled summer and winter non-weather-normal peak loads about their respected weather-normal peak load forecast. This chart shows that in the summer the peak load can be either 6.6% higher than the average or 6.8% lower than the average. In the winter, however, the peak load can as much as 22% higher than the average or 14.4% lower than the average. The chart also demonstrates that there is a significant possibility that the winter peak load in any given year can even be higher than the summer peak load.

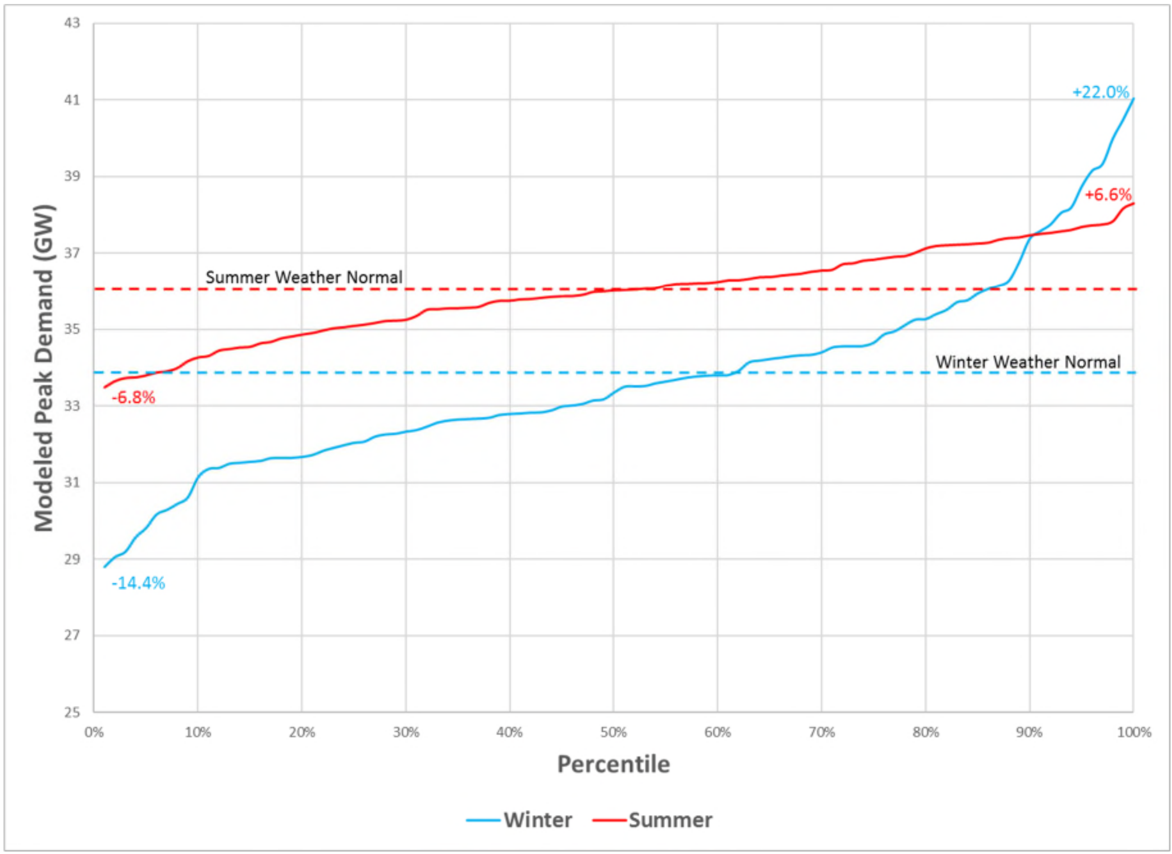

Figure A. 4. Distribution of Modeled Summer and Winter Peak Loads

[21] SERVM is a probabilistic reliability risk evaluation tool used in the Reserve Margin Study and other reliability analyses.

Of the 108 peak loads *modeled* in SERVM, there are 23 winter peaks greater than their respective summer peaks, representing roughly a 20% probability that the winter peak will be higher than the summer peak in any given year. This is consistent with what has been historically experienced. As shown in Figure A. 5 below, there have been two out of the last 10 years (2014 and 2015) in which the *actual* winter peak was higher than the actual summer peak.

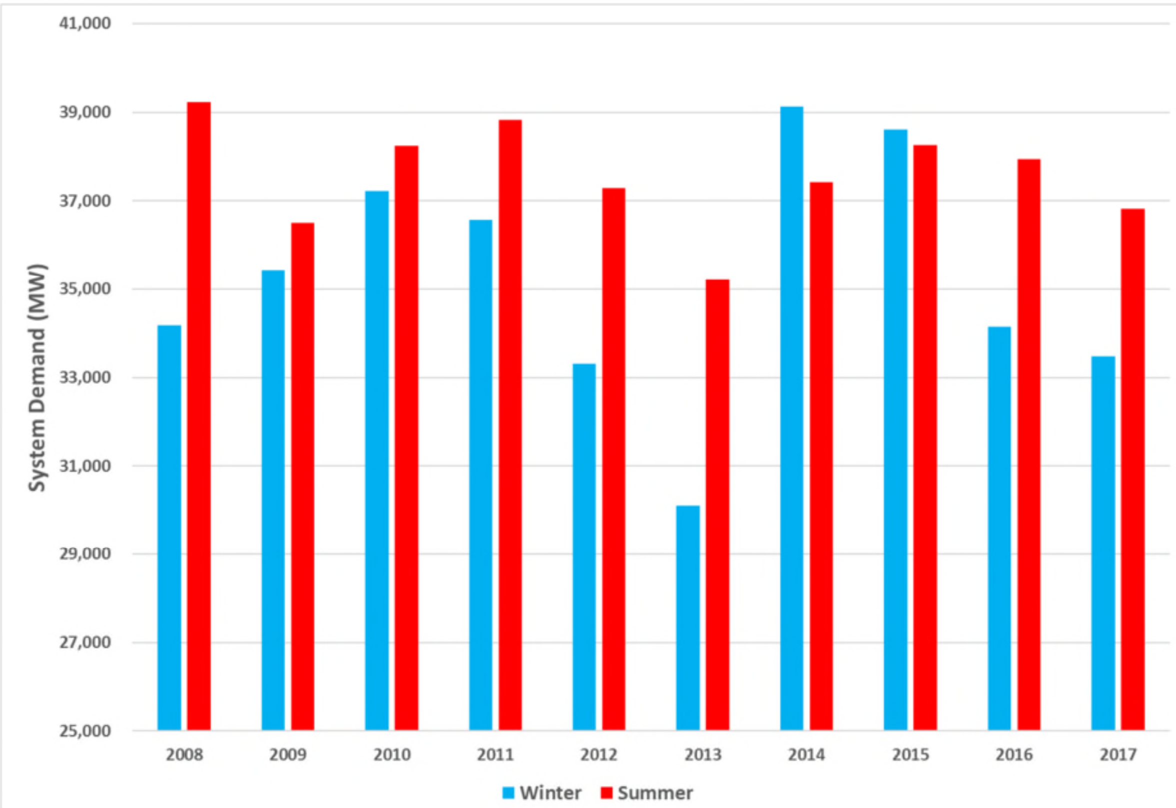

Figure A. 5. Historical Summer and Winter Peak Loads

Note: Figure shows total aggregate load dispatched within the Southern Company Pool.

B.3 Cold-Weather-Related Unit Outages

Extreme cold-weather conditions often result in increased unit outage rates. History has demonstrated that as temperatures continue to decrease the outage rate tends to increase exponentially. While the causes (*i.e.*, the components impacted by the cold weather) may be different for each, steam generators, CCs, and CTs all have vulnerabilities to extreme cold temperatures. Table A. 1 below shows several historical dates when extreme temperatures have occurred on the system. Many of these caused significant outages on the system. The table demonstrates that the colder the temperature, the more likely weather-related outages will occur.

Table A. 1. Historical EFOR During Cold-Weather Events

Date of Event	System Weighted Temperature (F)	EFOR (% of System Capacity)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

After the 2014 Polar Vortex event, the Operating Companies began implementing measures to improve the performance of its resources under extreme conditions. Those measures included the development of Standards of Excellence procedures for preparing generating facilities for cold weather and the addition of freeze protection on certain vulnerable equipment. System plant performance experts are confident that these efforts to improve cold-weather performance will ultimately result in a reduction in cold-weather outages relative to historical trends. However, even with these improvements, there will always remain an exponentially increasing probability of performance risk as system-weighted temperatures reach the more extreme cold levels. Figure A. 6 below shows the trend of the total System outages from Table A. 1. It also shows that same trend adjusted by an assumed average base EFOR of [redacted], representing the incremental outage rate associated with cold weather. Finally, it shows those same incremental outage rates adjusted to reflect the expectation of improved performance over time.

REDACTED

Figure A. 6. Cold Weather Unit Outage Performance

B.4 Penetration of Solar Resources

While reasonably correlated to summer peak load periods, solar generation is not well correlated to winter peak load periods, which occur around dawn or dusk. Thus, solar resources contribute significantly more toward summer reliability than they do toward winter reliability. Therefore, unless planners are looking at the System from both a summer and winter TRM perspective, the addition of solar resources can give the false impression of increased overall reliability. If only the Summer TRM is considered, a significant penetration of solar resources may contribute toward meeting summer reliability needs but would not contribute significantly toward meeting winter reliability needs, leading to possible winter reliability concerns. Figure A. 7 below shows the expected penetration of solar resources on the System through 2021 along with their corresponding Incremental Capacity Equivalent ("ICE") summer and winter capacity values.

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Figure A. 7. Solar Resource Penetration

This relative seasonal performance of solar resources can be confirmed by observation of actual historical solar output across the top 20 load hours of the summer and winter peak seasons for the solar resources currently installed on the System. Figure A. 8 below shows the relative summer and winter output (as a percentage of nominal installed solar capacity) on the System since 2015 averaged over the highest 20 load hours in the summer and winter periods. Note that the comparison of the average output across the top load hours cannot be used to validate or compare with the ICE values because the two metrics have different meanings, and the historical observations are for only a few sample years. However, both metrics do indicate solar has significantly different contributions to reliability in the summer versus the winter, with significantly less in the winter compared to the summer.

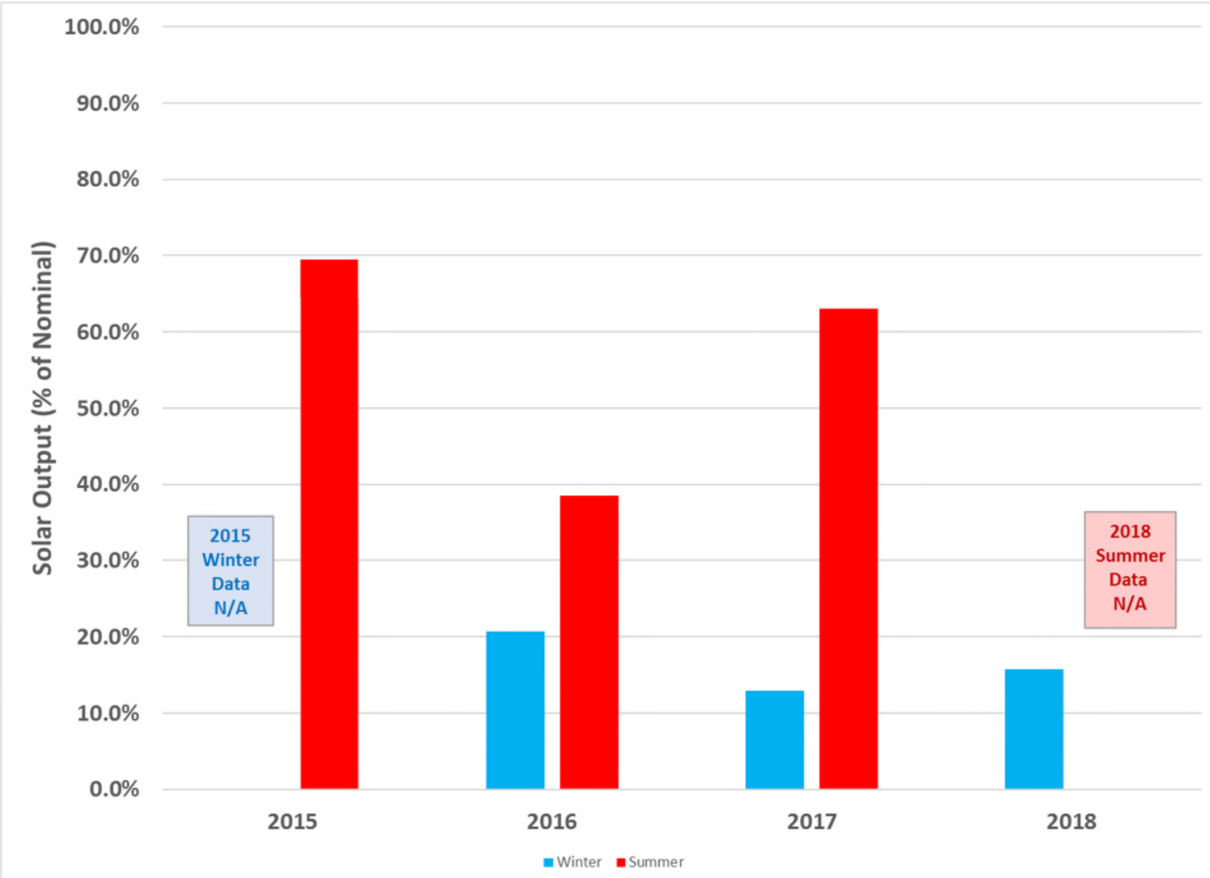

Figure A. 8. Solar Output During Highest 20 Load Hours

B.5 Increased Reliance on Natural Gas

Over the last decade, the System has increased its reliance on natural gas as a fuel source to meet its energy and demand needs. Figure A. 9 below shows the historical and future projected breakdown of energy by fuel type for the System, demonstrating the increased expectation for reliance on natural gas. The “coal or gas” slice in the 2027 Projected pie chart indicates uncertainty in coal vs. gas usage based on uncertainties in the forecasted price of natural gas.

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Figure A. 9. Historical and Projected Energy Use by Fuel Type

This increased reliance on natural gas increases exposure to gas delivery constraints, especially during winter peak conditions, because gas pipelines limit usage to firm transportation contracts. Figure A. 10 below demonstrates that over the last 6 years (2012 thru 2017), most operational flow orders[22] issued by the two primary pipelines that serve the System have occurred during the winter months.

[22] Operational flow orders are issued by pipeline operators when demand for natural gas causes constraints on the pipeline such that only those holding firm gas transportation contracts can utilize the pipeline.

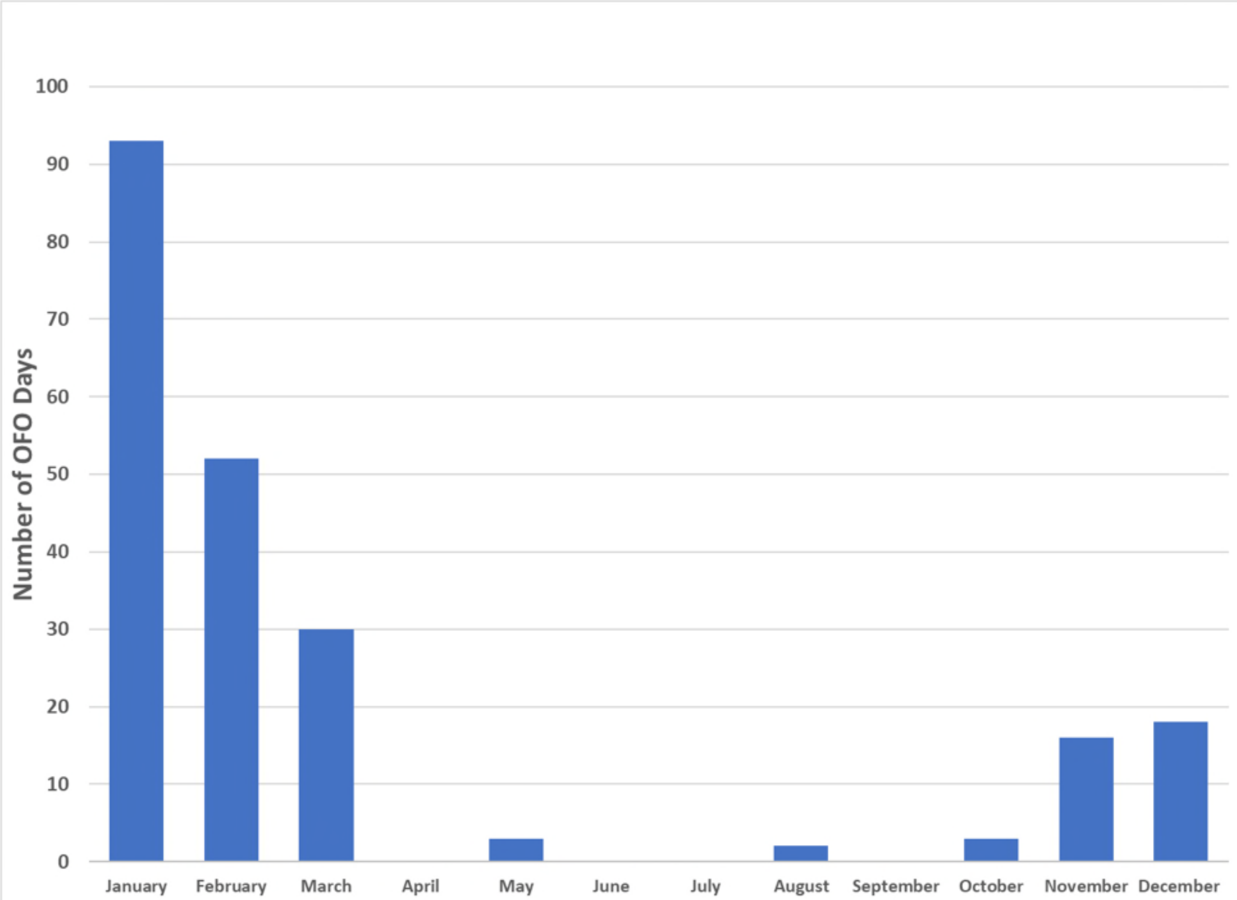

Figure A. 10. Monthly Distribution of Operational Flow Orders

To model the constraints associated with these operational flow orders, SERVM allows the user to phase out the availability of interruptible gas transportation based on the minimum and maximum daily temperature. When no interruptible transportation is available, the model only allows the unit to operate to the extent it has firm gas transportation or an alternative fuel supply such as on-site fuel storage. Figure A. 11 below shows the phase-in and phase-out of interruptible gas transportation as modeled in SERVM.

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Figure A. 11. Interruptible Gas Transportation Model

To mitigate the risk against these operational flow orders, the Operating Companies have a Fuel Policy that requires either on-site backup fuel (such as oil) or the acquisition of firm gas transportation from the pipeline. For CTs, the policy requires the equivalent of [redacted] of firm transportation. For CCs, the policy requires the equivalent of [redacted] of firm transportation for base mode operation and [redacted] of firm transportation for operation in full pressure modes. Unfortunately, while this policy is sufficient for typical (*i.e.*, normal) weather conditions, it can be insufficient for the most extreme weather conditions. As temperatures fall during the more extreme winter conditions, CTs may need to operate greater than [redacted] and CCs may need to operate in full pressure mode more than [redacted]. However, if the pipeline has issued an operational flow order, these resources will not be able to serve load once their firm gas transportation allocation has been fully utilized, resulting in unit outages during critical times causing either the need to operate more expensive oil facilities or, in the worst case, loss of load events. Additionally, the pipeline operators may limit the ability of the CTs to take the nominated natural gas across the [redacted] and force them to take the natural gas in equal increments across 24 hours, limiting the ability to use these resources to meet peak load. The Operating Companies continue to evaluate the risk of such events against the expense of additional firm gas transportation.

B.6 Market Purchase Availability

Traditionally, the reserve margin studies have modeled the regions surrounding the System to incorporate the availability of economic and reliability purchases from those regions. To avoid bias in the analysis results and not include purchases that might not be available in the real world, these regions are generally modeled at or near a reasonable level of reliability – specifically, they are modeled at or near a Loss of Load Expectation ("LOLE") of 0.1 days per year. This modeling effort already results in fewer purchases during the winter than in the summer. This is due primarily to the fact that when the System experiences very high demands resulting from extreme cold temperatures, the surrounding regions also experience those extreme temperatures and demands. Figure A. 12 below shows several recent cold-weather events and the amount of purchases that were available to the System at the time of the event.

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Figure A. 12. Historical Purchases During Cold-Weather Events

This kind of purchase availability restriction can occur during extreme summer temperatures as well, but not to the same degree as in the winter. This creates greater relative market availability risk in the winter than in the summer, further supporting the need to monitor and review winter reliability independently from summer. While absolute limits on purchases are not easily modeled within SERVM, operations personnel did provide purchase availability "targets" (rather than absolute limits) for use in the 2018 Reserve Margin Study. Those targets were implemented by a combination of sales price limitations and hurdle rates between regions.

C. Aggregate Impacts of Drivers on Winter Reliability

Over the past several years, significant efforts have been made to model these winter reliability drivers. The result has been an improvement in the reliability model that more closely matches what has been seen historically in the operational world. The following demonstrates how the modeling of these key drivers has impacted winter reliability.

C.1 Total Available Capacity by Season

In updating unit and system assumptions, one of the impacts that has resulted is a reduction in relative capacity during the winter months as compared to the previous study. In the 2015 Reserve Margin Study, there was considerably more total available capacity at lower winter temperatures than at summer temperatures. It is still true that many resources, such as CTs and CCs, have greater capacity output during cold temperatures than they have during hot temperatures – and were modeled as such in the 2018 Reserve Margin Study. However, not all resources can be depended upon for that additional capacity. Several of the CT and CC resources available to the System are Power Purchase Agreements ("PPA") that have contractual limitations on the amount of capacity that can be depended upon on a firm basis. While the resource may be able to produce more during the winter, the System does not have firm access to that additional capacity and the counterparty may not be obligated to provide the additional capacity available in the winter. Furthermore, the additional capacity that is available from other CT and CC resources is offset by the lower capacity contributions of solar and demand-side resources in the winter relative to summer. Figure A. 13 below shows that there is very little difference in the available capacity at a System-weighted temperature of 95ºF than there is at either 40ºF, 20ºF, or even at 10ºF.

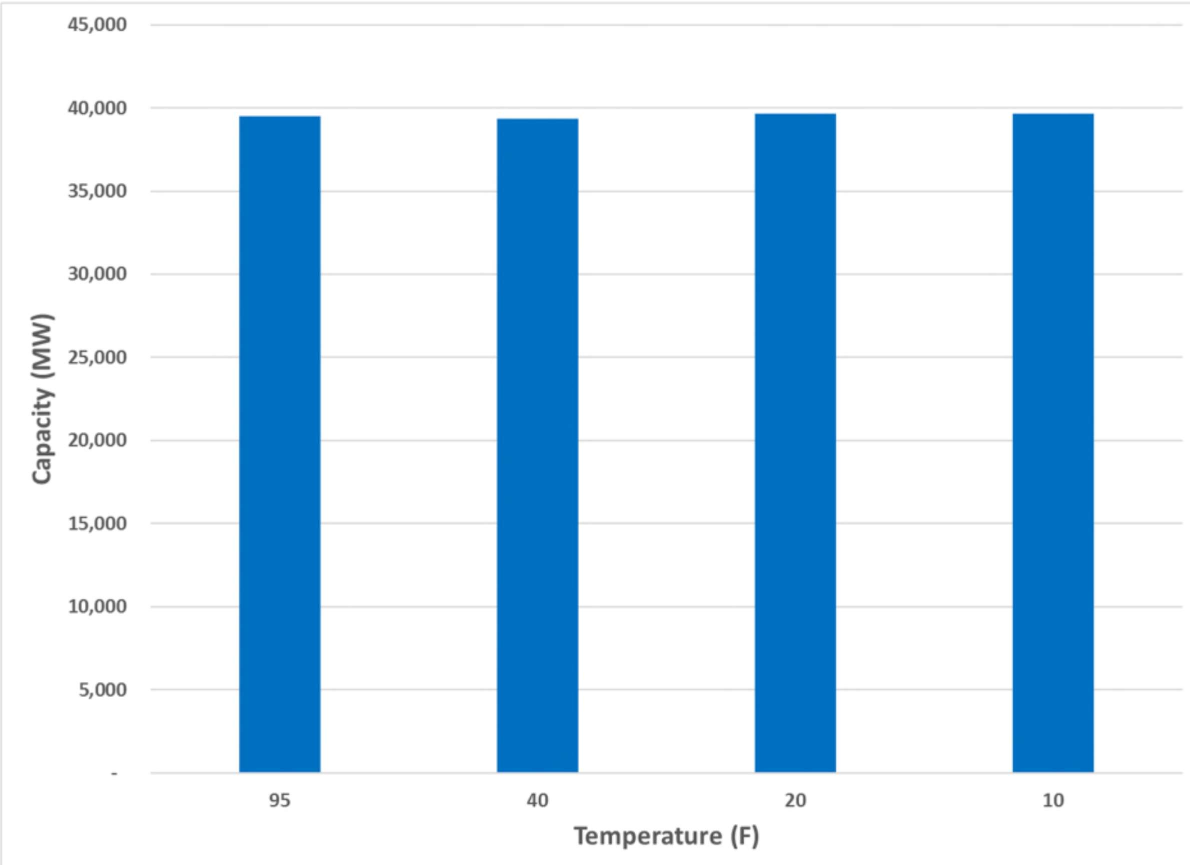

Figure A. 13. Total Available Capacity by Temperature

C.2 EUE by Season

Upon modeling these key drivers, the reliability model shows greater probability of EUE in the winter than has been previously shown. Figure A. 14 below shows the seasonal distribution of EUE at various (summer-oriented) reserve margins. The chart shows that at very low reserve margins, there is significant EUE in both the summer and winter periods. As reserve margin increases, the EUE in both the summer and the winter decreases. However, the EUE decreases much more rapidly in the summer than in the winter. In the winter, there is a probability of substantial EUE even at higher reserve margin levels. This is because the most extreme winter conditions in the model, while having a very low probability of occurrence, have a very high impact on EUE.

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Figure A. 14. Seasonal EUE by Reserve Margin

C.3 LOLE by Season

Another way to view the relative risk between summer and winter is through the LOLE. LOLE, expressed in number of days of outage per year, shows the probability that an EUE event will occur in any given month or year. Therefore, while the EUE metric shows both the magnitude and probability of risk, LOLE focuses only on the probability of event, so it is not biased by the occurrence of large EUE events. The figure below shows the relative LOLE for both summer and winter. This chart demonstrates that at lower reserve margins, there is a significantly higher probability of a summer-related event, but at the higher levels, the probability of a winter-related event is greater. Taking Figure A. 14 and Figure A. 15 together, it can be concluded that the summer-related events are relatively small in magnitude while the winter-related events are very large in magnitude. Because the probability of those events remains even at high reserve margins, it becomes necessary to give particular attention to those winter-related risks.

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Figure A. 15. Seasonal LOLE by Reserve Margin

D. The Nature of the Winter Reserve Margin

Traditionally, reserve margins have been stated in terms of summer peak demands and summer capacity ratings as stated in the following formula:

$$TRM = \frac{TSC - SPL}{SPL} x\ 100\%$$

Where:

TRM = Target Reserve Margin;

TSC = Total Summer Capacity; and

SPL = Summer Peak Load.

This traditional representation is essentially a Summer TRM and has been the only reserve margin considered because the System (in aggregate) has always been, and remains, summer peaking on a weather-normal basis. These traditional reserve margins stated in summer terms have historically been in the 15-17% range.

However, reserve margins can just as easily be stated in alternate terms. In fact, the traditional Reserve Margin Study is based on an evaluation representing the simulation of an entire year – in fact thousands of alternative simulations of that one year. When the traditional reserve margin is calculated, what is being determined is a specific number of megawatts that are needed relative to peak load. Those megawatts include an underlying existing system (at a 10% reserve margin) and a certain number of reliability CTs added that represents the minimum total cost across the entire year. Once that has been established, a reserve margin can be calculated. That reserve margin is traditionally calculated based on a snapshot of a single hour in that year-long evaluation – the weather-normal summer peak against the official summer unit ratings. However, there are 8,760 hours in the case, each representing different load values and different amounts of total capacity because rated output of the resources in the case changes due to variations in temperature. Therefore, one could theoretically say there are 8,760 different reserve margins in that case – one for each hour of the year. Of present interest, however, are just the summer peak and the winter peak. Just as a summer reserve margin is a snapshot of the summer peak hour against summer capacity ratings, the winter reserve margin is a snapshot of the winter peak hour against the winter capacity ratings. That winter reserve margin is represented by the following formula:

$$Winter\ TRM = \frac{TWC - WPL}{WPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TWC = Total Winter Capacity; and
WPL = Winter Peak Load.

Because winter peak loads are different (lower for a summer peaking utility) than summer peak loads and because winter generating capacity can be different than summer generating capacity, the Winter TRM can be higher than the Summer TRM. The extent to which the Winter TRM is higher than the Summer TRM depends on the relationship between the total available capacity in the summer versus the total available capacity in the winter as well as the differences in the weather-normal summer and winter peak loads. It is not out of the question for a Summer TRM of 15% or 16% to have an equivalent Winter TRM in the mid-to-upper 20s. ***However, this Winter TRM represents both the same cost and the same level of reliability as its Summer TRM equivalent*** – despite the appearances of being a “higher” reserve margin.

To illustrate this relationship, it is possible to take a snapshot of the System at a given moment in time and create a waterfall chart that demonstrates how to translate a summer reserve margin into a winter reserve margin. Figure A. 16 below illustrates this reserve margin translation from summer to winter. Reading the chart from left to right, a 16.25% summer reserve margin is based on summer total available capacity and the summer peak load. However, when moving from summer to winter there are various changes associated with increases or decreases in capacity. This is because some resources have higher capacity ratings in the winter versus the summer and others have lower capacity ratings in the winter versus the summer. Finally, there is a difference in the summer peak load and the winter peak load as well. In the example of Figure A.16, a 16.25% summer reserve margin is equivalent – that is, it has the same cost and the same level of reliability – to a 24.7% winter reserve margin.[23] In other words, if a Reserve Margin Study indicated the need for a 16.25% summer TRM, then it likely also indicated the need for a 24.7% TRM in the winter – especially if the study showed significant EUE potential in the winter.

[23] The 24.7% winter equivalent is based on the study case where the system is reduced to a summer reserve margin of 10% and restored to 16.25% using incremental CTs (consistent with how the Reserve Margin Study is performed).

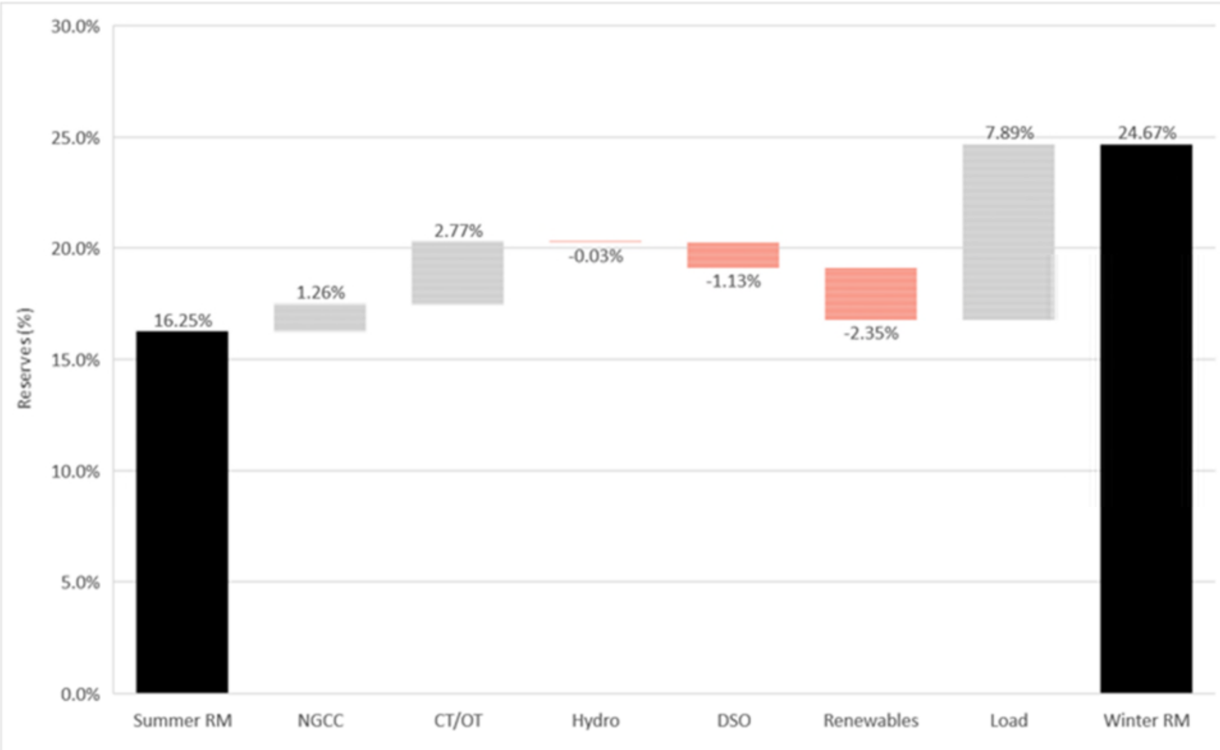

Figure A. 16. Winter Equivalent Waterfall

It should be carefully noted, however, that this waterfall chart is based on a snapshot in time. If anything changes on the System that changes the relationship between summer and winter, this equivalency changes.

E. Resulting Need for Winter Target Reserve Margin ("TRM")

Because the equivalency between summer and winter can change depending upon System conditions, it would be dangerous to only consider the summer TRM of 16.25% when planning the System and presume the winter will always have the necessary 24.7%. For example, if a coal unit were retired and replaced with a CC of equal summer capacity, the winter reserve margin would be higher than 24.7%. This is because a coal unit has the same ratings for both summer and winter while a CC may have more capacity in the winter. Similarly, if a CT were retired and replaced with a solar facility, the winter reserve margin would be lower than 24.7% because the CT has higher capacity in the winter relative to summer, but a solar facility's capacity contribution is less in the winter. Likewise, if the winter peak load forecast increased relative to the summer, the winter reserve margin would be lower than the 24.7%.

This changing winter equivalency phenomenon can be demonstrated by examining how the winter equivalent of the currently approved 16.25% TRM (a summer-oriented value) has changed since the 2015 Reserve Margin Study. The 2015 Reserve Margin Study first introduced some of these winter reliability risks as the reason for the increase in reserve margin at that time from 15% to 16.25%. The winter equivalent of 16.25% from that study – if it would have been calculated at that time – would have been 26% for a study year of 2019.[24] That reliability case was based upon Budget 2016. When reliability cases were updated for Budget 2017, the study year was moved to 2024 and the winter equivalent of 16.25% reduced from 26% to 25.6%.[25] When reliability cases were updated for Budget 2018, the study year was moved from 2019 to 2025; and the winter equivalent of 16.25% dropped again to the 24.7% shown in Figure 16 above. However, that 24.7% is based upon the theoretical situation in which the System is reduced to 10% and restored to 16.25% using incremental CTs. The actual winter equivalent of the existing system if it were reduced from its current state down to 16.25% would only be 23.7%. In other words, if planners only evaluate the system using the 16.25% Summer TRM, they could be misled into believing the system had adequate reliability in the winter (i.e., the presumed 26% winter equivalent required by the 2015 Reserve Margin Study) when the reality would be that the System only had 23.7% in the winter. This could lead to an unexpected and unforeseen reliability event in the winter such as what happened with the Polar Vortex event of 2014.

The Reserve Margin Study identifies the amount of reserves needed to maintain the proper economic and reliability balance in both the summer and winter seasons. It is the requirement identified by the study, not the changing equivalence, that should be considered as part of the planning process. Only considering the Summer TRM from the study essentially plans to the changing equivalence, not the requirement identified in the study, which could be misleading. Therefore, it is necessary to calculate both the Summer TRM and the required Winter TRM and then monitor and plan to both accordingly.

[24] This winter equivalent is based on reducing the system to 10% and restored to 16.25% using incremental CTs.
[25] This winter equivalent is based on reducing the existing system down to 16.25%; reducing the system to 10% and restoring with incremental CTs would result in a winter equivalent of 26.5%.

F. Conclusion

In conclusion, when the determinants and the resulting impact on seasonal reliability are carefully considered, continuing to plan the System using only a single (summer-oriented) TRM will increase the likelihood of an unforeseen loss of load event like the one that occurred in January 1977 and like what could have happened in January 2014. Therefore, while it may not be possible or cost-effective to completely eliminate the possibility of a winter loss of load event, it is necessary to establish and plan the System on a seasonal basis, with both a Summer TRM and a Winter TRM, to provide the appropriate level of mitigation against such risks.

Appendix B – Capacity Worth Factors

A. Background

Capacity Worth Factors ("CWFs") represent the relative worth of capacity from one period to another (*i.e.*, hour, month, season, etc.). As such, they represent the relative risk of a reliability event from one period to another. CWFs are developed hourly using the SERVM reliability model and from that model, represent the hourly improvement in reliability associated with a "perfect" megawatt (i.e., a megawatt that is available every hour of the year). CWFs can be represented hourly or they can be aggregated and represented monthly or even seasonally. CWFs are calculated at the Target Reserve Margin and so are a downstream output of the Reserve Margin Study and the associated approved Target Reserve Margin.

CWFs in some form are used in almost all System-wide analyses when deriving capacity value, including:

- IIC reserve sharing,
- PRICEM analyses,
- Retirement studies,
- Power Purchase Agreements,
- ICE Factors for the IRP, and
- Renewable Cost Benefit Analyses.

B. The SERVM Reliability Cost Report

The Capacity Worth Factor Table ("CWFT") is derived from the Reliability Cost report produced by the SERVM model. The Reliability Cost report generates the weighted sum of:

(a) the cost of EUE, plus
(b) the cost of expected Reliability Purchases, plus
(c) the cost of any Spinning, Supplemental, or Regulating Reserve shortfall.

Unlike the Reserve Margin Study, when calculating the CWFT, the Company is not interested in cost impacts, but rather in reliability impacts. Therefore, the CWFT is calculated only considering the probability and magnitude (not cost), resulting in a MW-weighting of the potential events identified above. To accomplish this, these events are all modeled with equal costs so that the Reliability Cost report is effectively only weighting these components based on MW impact, not relative cost, using the following modeling techniques:

- Reliability Purchases (defined as any purchase that avoids EUE) are determined by running the SERVM simulation as a "Southern-Only" case; this eliminates the model's ability to make reliability purchases which, in effect, treats Reliability Purchases as EUE.
- Spinning, Supplemental, and Regulating Reserves are modeled such that load will be curtailed to prevent a shortfall, thus also valuing those shortfalls as EUE.

Figure B.1 below shows all reliability components and which ones are included in the Reliability Cost report as inputs into the CWFT calculation.

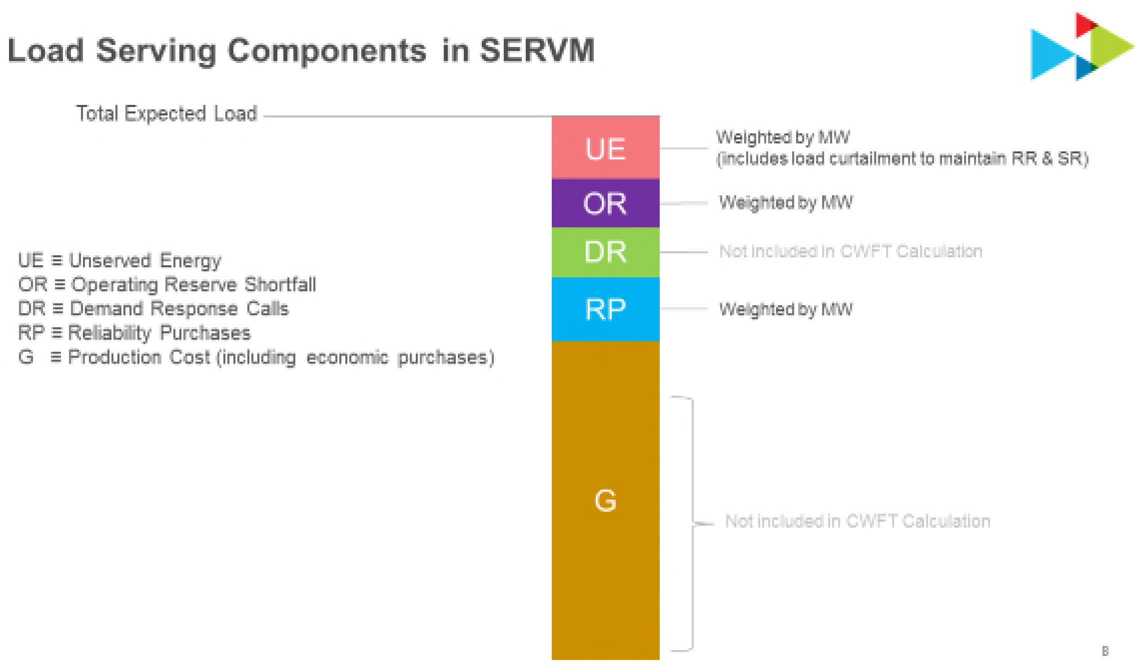

Figure B. 1 Treatment of Reliability Components in the CWFT Calculation

The Reliability Cost report can be generated using a combination of EUE Capacity, EUE IntraHour, EUE MultiHour, Net Purchases, and Production Cost. To generate the appropriate CWFT using this methodology, the Reliability Cost report is generated using EUE Capacity, EUE Intra-Hour, and EUE Multi-Hour (not Net Purchases and not Production Cost).

C. Capacity Worth Factor Results

CWFs are updated with each budget cycle. The 2018 Reserve Margin Study was performed using Budget 2018 (“B2018”) vintage data for inclusion in the 2019 IRP. CWFs resulting from the 2018 Reserve Margin Study will not be officially available until after the Budget 2019 (“B2019”) Reliability Base Case has been developed and so should be available in the first quarter of 2019. However, a 12x24 representation of the CWFs associated with the B2018 vintage data are shown in Tables B.1 and B.2 below.

Table B.1 shows the CWFT assuming the currently approved 16.25% TRM without Seasonal Planning.

REDACTED

Table B. 1 B2018 Vintage CWFT at 16.25% Summer TRM (Central Prevailing Time)

Table B-2 shows the B2018 Vintage CWFT assuming the approval of the proposed 26% Winter TRM.

REDACTED

Table B. 2 B2018 Vintage CWFT at 26% Winter TRM (Central Prevailing Time)

These tables will change once the Reliability Base Case has been updated for B2019 vintage planning assumptions. Furthermore, Table B-2 should be considered preliminary and indicative only. Table B-2 as shown above has not been used for the purposes of evaluating any renewable resource or any other resources.

Because the 26% Winter TRM is the dominant factor for System reliability, upon approval of seasonal planning, the official CWFT for the System will be the CWFT associated with the 26% Winter TRM.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. ________**

DIRECT TESTIMONY OF MICHAEL A. BUSH
ON BEHALF OF ALABAMA POWER COMPANY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Michael A. Bush. I am the Manager of Generation Planning and Development for Southern Company Services, Inc. ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q: DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A: I graduated from Auburn University with a degree in Electrical Engineering in 1987. After working outside the Southern Company for a brief period, I joined Mississippi Power Company in 1990 (having worked there as a cooperative student while at Auburn). I remained at Mississippi Power until 1995, at which time I transferred to SCS in Birmingham, Alabama to work in the wholesale marketing organization. In 1996, I became a wholesale electricity term trader and in 1999 I was appointed Manager of Energy Trading. In 2003, I took the position of Director of Portfolio Management, and in 2009, I moved to my current role as Manager of Generation Planning and Development ("GPD").

Q: WHAT ROLE DOES SCS SERVE RELATIVE TO ALABAMA POWER COMPANY?

A: SCS is a centralized service company that provides various services to Alabama Power and other operating companies on the Southern Company system at their direction and at cost. These services include, but are not limited to, accounting, contract administration, engineering, and fuel procurement, as well as the services provided by GPD.

Q: DESCRIBE YOUR PROFESSIONAL DUTIES AND RESPONSIBILITIES AS MANAGER OF GPD.

A: I hold primary responsibility for all of the generation planning and development services provided by GPD. These services include supply side technology evaluations and integration, asset valuation, asset acquisition, project development and asset implementation for the retail operating companies.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: Alabama Power has petitioned the Alabama Public Service Commission ("APSC") for a certificate of convenience and necessity, by which the Company would be granted the authority to acquire certain rights and assume certain obligations relating to several generation resources. These resources have been identified by Alabama Power as necessary and appropriate additions to its existing generation fleet, in order to continue to serve reliably the electricity demands of its customers. One of those resources is a new combined cycle gas turbine ("CCGT") facility at the Company's existing Plant Barry. The purpose of my testimony is to provide additional details regarding this facility, which I will refer to as Barry Unit 8, including the manner by which it would be delivered to the Alabama Power system. I will also overview the process that led to its identification as a cost-effective generation resource option for Alabama Power and its customers.

Q: WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A: In Part II of my testimony, I provide a high-level technical overview of Barry Unit 8, including its fundamental design parameters and operating characteristics. In Part III, I discuss the manner by which Barry Unit 8 will be constructed and placed into service, if the APSC grants Alabama Power a certificate of convenience and necessity for the facility. As part of this discussion, I provide context for the turnkey Agreement for Engineering, Procurement and Construction ("EPC Agreement") that Alabama Power, by and through SCS acting as its agent, has entered into with Mitsubishi Hitachi Power Systems Americas, Inc. ("MHPS") and Black & Veatch Construction, Inc. ("B&V"). Although the EPC Agreement itself is a complex collection of documents and materials, at its essence the agreement provides for the turnkey delivery of a new generating facility by MHPS and B&V by November 1, 2023. In Part IV, I discuss the process that gave rise to the execution of the EPC Agreement, including the manner by which the appropriateness of the turnkey option as a potential resource addition for Alabama Power was determined. Part V of my testimony provides concluding remarks.

II. BARRY UNIT 8

Q: DESCRIBE BARRY UNIT 8.

A: Barry Unit 8 will provide approximately 726 MW (nominal/winter) of CCGT generating capacity at the initial commercial operation date. Following a post-48 month uprate, the unit will have a winter capacity of 743 MW. The principal components of Barry Unit 8 include one Mitsubishi 501 J-series air-cooled combustion turbine, one heat recovery steam generator with duct firing, and one condensing reheat steam turbine (together comprising a 1-on-1 combined cycle configuration), along with other balance of plant equipment, including a cooling tower for closed-cycle cooling operations. The unit is expected to have an average heat rate of 6,210 Btu/kWh, and an expected useful life of 40 years.

Q. WHAT IS THE EXPECTED ANNUAL OUTPUT OF BARRY UNIT 8?

A: Again, the expected winter output of the unit at delivery is 726 MW (at ambient conditions of 28ºF and 68 percent relative humidity). The expected summer output at delivery is 653 MW (at ambient conditions of 94ºF and 47 percent relative humidity). As the seasonal differential implies, variable conditions, such as ambient temperature, relative humidity, Btu content of natural gas delivered to the unit, and other factors, will affect actual unit capability. Following a scheduled uprate after the unit has been in operation for 48 months, the winter and summer capacities will be 743 MW and 685 MW, respectively. While minimal deviation may occur, MHPS and B&V must remedy any material deviation. Later in my testimony I discuss how the EPC Agreement provides for these assurances.

Q: WHAT ARE THE ADVANTAGES OF CCGT TECHNOLOGY?

A: As reflected in Alabama Power's integrated resource plan (discussed in the testimony of Mr. Kelley), CCGT technology has been identified as one of the candidate technologies to meet the Company's incremental capacity and energy needs. CCGT is a proven means for utilities to reliably and cost-effectively satisfy the electricity needs of their customers. The generators are highly efficient at converting fuel to electric power, and offer a significant degree of flexibility, in terms of following swings in system load and responding quickly to system dispatch signals. At present, there are approximately 260 gigawatts of installed CCGT capacity in the United States.

Q: DOES ALABAMA POWER HAVE EXPERIENCE OPERATING A CCGT?

A: Yes. Plant Barry Units 6 and 7 are CCGT technology and have been in service for nearly 20 years. Note too that Alabama Power generating facilities are dispatched as part of the larger Southern pool, with SCS serving as the agent for the Southern operating companies in the execution of unit commitment and dispatch responsibilities. At present, the pool controls the dispatch of 13 CCGT facilities consisting of 22 units across the entire Southern system.

Q: IS THE J-SERIES DESIGN A PROVEN TECHNOLOGY?

A: Yes. CCGT technology has been employed for decades, and MHPS's gas turbine reflects design characteristics originally adopted in the 1970s. The J-series design itself has been deployed in 39 units worldwide with more than 800,000 operating hours logged. The J-series with air cooling represents an evolution of earlier MHPS technologies, through the integration of air cooling for combustors instead of steam cooling. At present, five air cooled J-series units are in operation, with more than 19,000 operating hours logged. I would also note that MHPS plays a key role throughout its production process, from development, design and manufacturing, to testing and commissioning, to post-deployment servicing. Indeed, in advance of commercial deployment, MHPS operates new designs at an actual load-serving test facility in Japan, in order to verify the systems through practical application.

Q: WHERE AT PLANT BARRY WILL THE NEW UNIT BE LOCATED?

A: Barry Unit 8 will be sited south of Units 6 and 7, which facilitates the use of existing infrastructure, including natural gas, electric transmission, and water facilities, as well as civil infrastructure (e.g., rail, barge and highway). Plant Barry itself is located in Bucks, Alabama.

Q: WILL NEW INFRASTRUCTURE BE REQUIRED TO ACCOMMODATE BARRY UNIT 8?

A: Certain new infrastructure will be required, including: a new tie line to the existing adjacent Ellicott 230 kV substation; a gas extension line from the existing Plant Barry gas yard to the location of the new unit; new water lines; and a new access road connecting two existing plant roads.

Q: WILL THE OPERATION OF BARRY UNIT 8 AFFECT THE OPERATIONS OF ANY OF THE OTHER PLANT BARRY UNITS?

A: No. All remaining units can continue operating during the construction of Barry Unit 8 and after it is placed into service.

III. THE EPC AGREEMENT

Q: PLEASE EXPLAIN HOW ALABAMA POWER PROPOSES TO CONSTRUCT BARRY UNIT 8.

A. Alabama Power is proposing that Barry Unit 8 be constructed by MHPS and B&V in accordance with the EPC Agreement that the Company has entered into with those parties. The EPC Agreement comprises a number of contract documents, including specifications and schedules that are referenced in the agreement itself. Key portions of the EPC Agreement are included with my testimony at Exhibit MAB-1. Under the EPC Agreement, MHPS and B&V will serve jointly and severally as the contractor for the project. I would observe that the EPC Agreement does provide an option for a second unit. Alabama Power has determined, however, to request certification only of a single unit (i.e., Barry Unit 8). The process utilized by Alabama Power to determine the appropriate and cost-effective composition of new generation capacity reflected in the

Company's petition for a certificate of convenience and necessity is discussed more fully in the testimony of Messrs. Kelley and Looney.

Q: WHAT ARE THE KEY MILESTONES FOR CONSTRUCTION OF BARRY UNIT 8?

A: Like most projects of this type, the EPC Agreement specifies certain stages at which a prescribed degree of facility design and construction has been completed. These include the contract execution, limited and final notices to proceed, receipt of permits, full mobilization, mechanical completion and substantial completion. Importantly, the EPC Agreement specifies a "Guaranteed Substantial Completion Date" for Barry Unit 8 of November 1, 2023. By that date, MHPS and B&V must, among other things, have completed construction activities at the unit such that it is capable of demonstrating specified performance guarantees. Other specific milestone dates include: a limited notice to proceed by March 2020 for engineering and design; full notice to proceed on the project by November 1, 2020; full site mobilization by May 1, 2021; and the availability of auxiliary power for the facility by December 2022.

Q: HAS ANY WORK COMMENCED ON THE PROJECT ALREADY?

A: Yes. In order to fully implement the EPC Agreement and to ensure sufficient time to meet the November 1, 2023 Guaranteed Substantial Completion Date, some limited site investigation has commenced. In addition the EPC Agreement contemplates the commencement later this year of certain work on external infrastructure (e.g., the plant access road I noted earlier).

Q: WHAT ROLE WILL ALABAMA POWER HAVE DURING CONSTRUCTION OF THE UNIT?

A: Given the size of the project and the fact that it will be taking place at an operating generating facility, Alabama Power and SCS will maintain personnel on site to coordinate the activities of MHPS and B&V with ongoing operations and to confirm the project is proceeding according to the baseline schedule.

Q: WHAT IS THE ESTIMATED COST OF THE PROJECT?

A: The estimated in-service cost of the project is approximately [redacted], which includes costs related both to the EPC Agreement as well as costs associated with Alabama Power's ownership and management of the project (along with pre-delivery O&M and start-up costs and a management contingency reserve).

Q: CAN YOU FURTHER DELINEATE THE TYPES OF COST COMPONENTS WITHIN THE FIRST CATEGORY OF COSTS?

A: The EPC Agreement costs are those contemplated by the agreement between the Company and MHPS and B&V, which will be billed to the Company upon completion of the various milestones set forth in the agreement. These costs include:

- Engineered equipment, such as the J-series combustion turbine generator, the steam turbine generator, the heat recovery steam generator, and boiler feed pumps;
- Engineering and construction management services, including design, development and procurement, project controls, and scheduling;
- Design and construction of certain external infrastructure, including roads, water and gas lines, and pump structures;
- Supervisory and administrative staffs at the construction site;
- Subcontractors and craft laborers (such as welders, electricians and pipefitters);
- Construction materials (such as copper, steel and concrete) used by the contractors and their subcontractors;
- Indirect construction costs (such as scaffolding and safety equipment);
- Sales and use taxes incurred by MHPS and B&V; and

- Labor- and materials-related costs associated with start-up and commissioning of the unit.

Q: WHAT COST COMPONENTS ARE INCLUDED WITHIN THE CATEGORY OF OWNERSHIP- AND MANAGEMENT-RELATED COSTS?

A: The cost components that I reference here include:

- Company and SCS project management, including costs associated with project management, conceptual and detailed design review, project monitoring, and environmental permitting;
- Transmission-related infrastructure costs associated with the design and construction of facilities required to integrate Barry Unit 8 into the existing electric system;
- Project contingency, which reflects a general estimate of [redacted] of the total project cost to allow for presently unknown or unidentified circumstances that could affect the cost of the project;
- Project financing costs over the course of construction; and
- Pre-commercial operating date start-up costs, including fuel- and labor-related costs.

Q: DO YOU BELIEVE THIS ESTIMATE REASONABLY REFLECTS THE ULTIMATE COST OF THE PROJECT?

A: Yes. The EPC Agreement affords a significant level of certainty, insofar as the ultimate cost of the project is concerned. The EPC Agreement is a fixed-price turnkey agreement, and as I explain more fully below, represents the outcome of a process that saw multiple contractor consortiums (including MHPS and B&V) compete for the opportunity to deliver a new CCGT to Alabama Power. Throughout the process that led to the eventual execution of the EPC Agreement, GPD and others acting at its direction worked extensively to inform the scope of work applicable to the development of a new CCGT at Plant Barry. These efforts were intended to reduce the potential for change orders that might result in material cost increases.

Q: WHAT ASPECTS OF THE CONSTRUCTION PRICE ARE SUBJECT TO CHANGE?

A: While price certainty is the goal of the turnkey contract, the price for the construction of Barry Unit 8 is not fixed in absolute terms. First, the ownership- and management-related costs are a function of the construction oversight activities that prove necessary to deliver the unit in accordance with the EPC Agreement. As for activities under the EPC Agreement, there is the prospect for a change event, which is a prerequisite under the agreement for a change order. The EPC Agreement limits the opportunities for change events, as I explain below. More importantly, MHPS and B&V are only entitled to a change in the price or an extension in the time to perform upon demonstration that the change event will have a direct, material, adverse and demonstrable impact on their ability to perform the work under the agreement for the stated price and within the specified time. In addition, MHPS and B&V are obligated to undertake commercially reasonable efforts to mitigate the effects of any change event prior to any change in price being allowed.

Q: WHAT CIRCUMSTANCES MAY GIVE RISE TO A CHANGE EVENT?

A: Under the EPC Agreement, change events are limited to those changes to the project directed by Alabama Power; an excusable delay that is caused by Alabama Power or an event of force majeure; the discovery of an unforeseen site condition; a change in law; and certain other discrete circumstances that are enumerated specifically in the EPC Agreement (e.g., damage to materials or equipment on site due to force majeure or wrongful acts of Alabama Power; the identification of unanticipated subsurface conditions). In short, matters that are beyond the control of MHPS, B&V, or their subcontractors can give rise to a change event—but only upon satisfaction of the detailed preconditions set forth in the EPC Agreement can such a change event give rise to a change order and a potential modification of the price for the project or the schedule for its development and commissioning.

Q: EARLIER YOU REFERENCED PERFORMANCE GUARANTEES. CAN YOU EXPAND ON THOSE CONTRACT CRITERIA?

A: Under the EPC Agreement, MHPS and B&V must deliver a facility with a net output of 726 MW at 28ºF in the winter, a net output of 600 MW at 94ºF in the summer, and an average annual heat rate of [redacted] Btu/kWh. If the actual output of the unit is within [redacted] percent and the actual heat rate is within [redacted] percent of the guaranteed performance levels (and certain other guarantees are met), then MHPS and B&V have the option to perform additional work to reach the guaranteed performance levels or pay liquidated damages relative to the difference between the guaranteed and the actual performance levels in order to achieve substantial completion. I would emphasize that until the unit reaches the minimum performance levels, it cannot be deemed substantially complete. After approximately 48 months of operation time, MHPS has committed to perform an uprate on the facility. While precise output levels will ultimately depend on unit operation at the time of the uprate, it is expected that upon completion the unit will have a demonstrated winter capacity rating of 743 MW and a demonstrated summer capacity rating of 685 MW.

Q: ARE THERE OTHER GUARANTEES IN THE CONTRACT?

A: Yes. In connection with the performance guarantees just discussed, MHPS and B&V must deliver a project that meets specified emissions levels and noise levels. The EPC

Agreement also requires the facility to meet certain reliability guarantees. Specifically, for each of the [redacted] following substantial completion, the equivalent forced outage rate ("EFOR") at Barry Unit 8 cannot exceed [redacted] percent for the combined months of January, February, June, July and August (i.e., months corresponding to the expected winter and summer peaks). In addition, the annual EFOR cannot exceed [redacted] percent. For clarity, EFOR under the EPC Agreement covers forced outages and unit derates not otherwise caused by Alabama Power's failure to operate and maintain the facility in accordance with manufacturer's guidelines.

In addition, the EPC Agreement provides for [redacted]

Q: EARLIER YOU STATED THAT MHPS AND B&V WILL BE ACTING JOINTLY AND SEVERALLY. WHAT IS THE SIGNIFICANCE OF THIS DESIGNATION?

A: I believe this is one of the more unique aspects about the EPC Agreement. Alabama Power has been able to secure the services of an experienced, large project contractor (i.e., B&V) as well as the original equipment manufacturer ("OEM") itself (i.e., MHPS) jointly and severally as the designated contractor for design, procurement and construction of the entire unit. This arrangement provides enhanced protection for Alabama Power and its customers against liabilities that may arise in the unlikely event of a failure of performance. In other words, Alabama Power is able to look to either or both of the parties for satisfaction of all obligations assumed individually and collectively by them under the EPC Agreement. In addition, fulfillment of these joint and several obligations is backed by parent guarantees for both MHPS and B&V.

Q: ARE THERE OTHER FEATURES OF THE EPC AGREEMENT THAT SERVE TO MITIGATE RISKS TO ALABAMA POWER AND ITS CUSTOMERS?

A: As I explain below, the process that led to the execution of the EPC Agreement produced an arrangement that provides very favorable conditions to Alabama Power. Moreover, this process provided Alabama Power the opportunity to simultaneously negotiate and secure a long term service agreement ("LTSA") for Barry Unit 8. By securing the LTSA terms and conditions in advance of construction, Alabama Power was able to obtain competitive pricing considerations for services necessary for the long-term reliability of the unit.

IV. PROCESS FOR EPC AGREEMENT DEVELOPMENT AND EXECUTION

Q: DESCRIBE THE PROCESS THAT LED TO THE EXECUTION OF THE EPC AGREEMENT.

A: As I mentioned at the outset, GPD continuously investigates the availability of resources that the Southern operating companies might wish to consider as an option to meet the future needs of their customers. In connection with such efforts, GPD was approached in

2016 by the power generation division of a major OEM with a concept to provide a CCGT facility on a fixed-price turnkey basis.

Q: HOW DID YOU REACT TO THE PROPOSAL?

A: GPD saw upside in the proposal, particularly insofar as a fixed-price project could serve to mitigate risks inherent in the construction of a large-scale, long-lead time project like a new generation facility. Also, over the course of preliminary review of the concept, it became evident that seasonal planning considerations by Alabama Power could create a need for the addition of new generation capacity closely coinciding with the amount of time required to deliver a new CCGT facility (accounting for the necessary regulatory authorizations, as well as design, construction and commissioning). GPD and Alabama Power concluded, however, that a market solicitation of all major and internally approved OEMs had the potential to yield an even more competitive turnkey proposal. Accordingly, in early 2018, SCS solicited proposals on behalf of Alabama Power for the fixed-price delivery of a single turnkey CCGT unit at Plant Barry.

Q: WHAT ENTITIES RECEIVED THE SOLICITATION?

A: As I noted, the entities solicited included the major OEMs whose CCGT technology designs had been approved for deployment on the Southern system.

Q: WHY DID THE SOLICITATION CALL FOR PROPOSALS FOR A NEW UNIT AT PLANT BARRY?

A: Alabama Power has several candidate sites for future generation deployment, but Plant Barry was selected based on the anticipated cost savings associated with its ability to accommodate new unit construction and its ability to leverage existing infrastructure, including natural gas transportation capacity.

Q: DID THE SOLICITATION PROVIDE EXTENSIVE DETAILS REGARDING ALABAMA POWER'S EXPECTATIONS FOR THE PROPOSAL?

A: As the dedicated supplier of retail electric service to more than 1.4 million customers, Alabama Power has expectations regarding reliability of the systems used to fulfill that responsibility. Moreover, for a new generating unit to be sited at an existing, operating plant, a number of accommodations and protections also would have to be factored into any final agreement for engineering, procurement and construction. So to that extent, the proposal was prescriptive, and included a number of minimum operating, reliability and safety parameters appropriate for the commissioning of a generation facility at the Plant Barry site. However, in recognition of the experience and knowledge held by the OEMs, Alabama Power and SCS encouraged bidders to propose projects they believed would best suit the indicated needs and that OEMs believed most competitive.

Q: CAN YOU DESCRIBE THE SOLICITATION PROCESS?

A: The solicitation itself was issued in January of 2018, with final proposals received in August of 2018. In between the solicitation and response, the process underwent some evolution, which contributed to its duration. Initially, the solicitation contemplated the OEM serving as contractor under the EPC Agreement. Shortly after proposals were released, SCS and Alabama Power received inquiries as to their willingness to entertain a "consortium" response that included both the OEM and a more traditional construction service provider. Alabama Power saw value in such an approach, if the consortium partners agreed to joint and several liability under the EPC Agreement, as it not only retained the OEM as the primary party for the project, but also expanded responsibility to a second party, namely a proven contractor whose services likely would have been engaged on a subcontract basis upon issuance of any award. Each of the OEMs agreed to the joint and several construct and paired with a construction partner. Thereafter, SCS separately worked with each of the consortiums to answer technical questions informing their respective proposals.

Significant time also was spent with each consortium to negotiate the EPC Agreement that would be submitted with the proposal. Each consortium retained the option to tailor its proposal, with the understanding that material differences would be factored into the risk adjusted evaluation of the proposal. SCS also worked with each consortium on an LTSA for the project. As I mentioned earlier, there was significant value in securing the terms and conditions of the LTSA at this stage of project development, with the respective consortiums competing against one another. Developing the terms and conditions of these documents also contributed to the duration of the solicitation process.

Q: HOW WERE THE PROPOSALS EVALUATED?

A: The relative merits of the three proposals were considered against each other on a risk adjusted basis. In addition, the proposals were evaluated against the estimated cost of an internally developed self-build project at Plant Barry. The results of the evaluation demonstrated that the most cost-effective option, and one that included the myriad of risk mitigation features that I have discussed in my testimony, was the proposal by MHPS and B&V.

Following this determination, a preliminary award letter was delivered to MHPS and B&V by Alabama Power in November of 2018. The award letter recognized that a final determination to proceed with the proposal remained within the discretion of

Alabama Power. The reason for this reservation was twofold. First, the proposal still required consideration alongside other resource opportunities available to Alabama Power, to ensure that it represented a competitive cost-effective resource option. Second, a certificate of convenience and necessity would be required for Alabama Power to proceed fully under the EPC Agreement.

Q: WHEN WAS THE EPC AGREEMENT EXECUTED?

A: The agreement was executed in May 2019.

Q: WHAT CONTRIBUTED TO THE PASSAGE OF TIME BETWEEN THE PRELIMINARY AWARD LETTER AND THE EXECUTION OF THE EPC AGREEMENT?

A: During the solicitation, unrelated efforts were ongoing to update the labor agreement applicable to projects on the Southern system. After the preliminary award letter was issued to MHPS and B&V, that labor agreement was finalized. Thereafter, efforts were pursued with these parties to ensure that the EPC Agreement reflected the appropriate labor-related considerations arising out of the Southern system labor agreement. In addition, by that time, SCS and Alabama Power had gained a clearer understanding of what Alabama Power's capacity needs would be across the relevant time horizon. Accordingly, MHPS and B&V were asked to submit a proposal for the delivery of an optional second CCGT unit at Plant Barry. Lastly, MHPS and B&V were asked to include as part of this submittal a proposal to perform certain external infrastructure work. These factors contributed to the additional months needed to finalize and execute the EPC Agreement.

V. CONCLUSION

Q: DO YOU HAVE ANY CLOSING REMARKS?

A: Yes. As the foregoing discussion demonstrates, Barry Unit 8 represents a unique opportunity for Alabama Power to secure the addition of reliable, cost-effective capacity, in furtherance of its obligations to its customers. The EPC Agreement governing the design, construction and commissioning of Barry Unit 8 contains a number of features that are intended to shift the risks inherent in a project of this kind, thereby protecting Alabama Power and its customers and facilitating the commissioning of this resource in a timely manner.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY)
)
Petitioner)

DIRECT TESTIMONY OF MICHAEL A. BUSH
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA)

COUNTY OF JEFFERSON)

Michael A. Bush, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Michael Bush
Michael A. Bush

Subscribed and sworn to before me
this 4th day of September, 2019.

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

Notary Public

Direct Testimony of Michael A. Bush

Exhibit MAB-1

CONFIDENTIAL AND OMITTED

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. ________**

DIRECT TESTIMONY OF M. BRANDON LOONEY
ON BEHALF OF ALABAMA POWER COMPANY

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is M. Brandon Looney. I am the Manager of Reliability and Resource Procurement for Southern Company Services, Inc. ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A: I graduated from the University of Alabama with a degree in Mechanical Engineering in 2003, and received a Master of Business Administration degree from the University of Alabama in Birmingham in 2007. I am also a licensed Professional Engineer in the State of Alabama. I began my career with Southern Company in 2003 in the Engineering and Construction Services organization, working primarily on emissions control equipment. In 2007, I moved to Research and Environmental Affairs, where I focused primarily on technology solutions for the Mercury and Air Toxics rule. In 2012, I became the manager of the Emissions Control Research department. In 2013, I moved to the System Planning organization, where I have held several leadership roles in the areas of Asset Management, Renewable Development, and Environmental and Asset Planning. My current role of Manager of Reliability and Resource Procurement is also within that organization.

Q: WHAT ARE YOUR RESPONSIBILITIES AS MANAGER OF RELIABILITY AND RESOURCE PROCUREMENT?

A: I am primarily responsible for system reliability studies involving generation resource adequacy and support of the retail operating companies in their procurement activities related to generation resources. These efforts include structuring requests for proposals ("RFPs"), developing and negotiating contracts, and evaluating responses to RFPs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: Alabama Power has petitioned the Alabama Public Service Commission ("APSC") for a certificate of convenience and necessity, by which the Company would be granted the authority to acquire certain rights and assume certain obligations relating to several generation resources. As reflected in the testimonies of Messrs. Kelley and Bush, Alabama Power had a number of resource options to consider in determining an optimal solution for meeting its supply obligations to customers, including the construction of new generation facilities, the acquisition of existing generation facilities, and the entry into purchase power arrangements ("PPA"). My department worked with Alabama Power personnel to develop economic analyses of the competing resource options under consideration. The purpose of my testimony is to explain that process and the conclusions it yielded.

Q: DID ALABAMA POWER ASSIST WITH YOUR EVALUATION?

A: Yes. As Mr. Kelley discusses in his testimony, Alabama Power conducted the RFP process soliciting potential capacity offerings from wholesale market participants.

Among other things, it called for respondents to provide their proposals in a particular format, with generation resource ratings, operating characteristics, price and other relevant components of each proposal individually identified, and regardless of whether the respondent was proposing a PPA or an acquisition. This structure enabled my department to more readily evaluate the pertinent economic characteristics of the various proposals.

After receiving the bid proposals submitted in response to the RFP, Alabama Power first undertook a preliminary screen to identify any proposals that did not fundamentally comply with the RFP requirements. Alabama Power then supplied the compliant RFP bid proposals to my group, along with the turnkey proposal for Barry Unit 8, for detailed analysis. Forecasting and Resource Planning handled the economic evaluation of projects involving solar with battery energy storage systems ("Solar BESS"), doing so in a manner comparable to the analysis performed by my department. Those results were provided to my department for incorporation into the evaluation and ranking of all the resource options.

Q. PLEASE DESCRIBE THE PROCESS UTILIZED BY YOUR DEPARTMENT TO EVALUATE THE PROPOSALS.

A. The first step was the development of a reference case, which reflects the operation of the existing system (together with generic resource additions) over a 40-year evaluation period.

Q: WHY WAS 40 YEARS USED FOR THE EVALUATION PERIOD?

A: To conduct an analysis that includes proposals of varying unit lives and term lengths, it is necessary to set an evaluation period that encompasses the longest-lived proposal. That proposal was for Barry Unit 8, which has an expected service life of 40 years.

Q: WHAT DID YOU DO NEXT?

A: After we established the reference case, we determined how the inclusion of each proposed resource as a dispatch option in the reference case affected total generation cost. In making this assessment of each proposal's incremental impact to the system, we modeled all generation-related costs associated with the proposed resource, including capacity costs, fixed operations and maintenance ("O&M") costs, start-up costs, and natural gas transportation charges. Simulating a system dispatch of the entire Southern Company fleet of generating resources, including a given proposal, enabled us to quantify production cost savings (i.e., energy savings), while also capturing the projected commodity fuel and variable O&M costs associated with that proposal.

Q: CAN YOU ELABORATE ON THE VARIOUS COST COMPONENTS YOU MENTIONED ABOVE?

A: Capacity costs in our evaluation reflect the calculated revenue requirement or capacity payment that corresponds to the fixed cost obligation for a given proposal—that is, the cost to customers to construct, acquire, or contract for a generating resource that provides capacity. For resources that are under contract for sales to a third party, the expected sales revenues are credited against the capacity costs.

Fixed O&M costs are the projected fixed operating and maintenance costs associated with resources. For newly constructed resources, an estimate was included as part of the proposal. For acquisitions, an estimate also was included with the RFP response and was initially used in the evaluation. As the evaluation process progressed, however, Alabama Power refined that estimate based on its detailed investigation of the proposed facility.

Start-up cost represents the projected cost to start a thermal generating unit, accounting for the anticipated number of starts under economic dispatch and the cost characteristics of the resource. For contracted resources, the per-start cost was specified in the proposal.

Finally, the natural gas transportation charges reflect the cost of maintaining firm transportation capacity adequate to serve the unit. Projections of these costs were based on the RFP response itself or data developed by the Fuels Services group at SCS.

Q: HOW DID YOU RECONCILE THE DIFFERENCES IN UNIT LIVES AND LENGTH OF PPA TERMS IN THE VARIOUS PROPOSALS?

A: As I explained above, the 40-year expected useful life of Barry Unit 8 dictated the length of the evaluation period. We thus analyzed the economics of each proposal consistent with its proposed term—or in the case of acquisitions, their expected remaining lives—and then performed a similar economic assessment for replacement capacity for the balance of the evaluation period.

Q: WHAT ASSUMPTION DID YOU USE FOR THE REPLACEMENT CAPACITY?

A: We assumed the costs and energy benefits corresponding to a dual-fueled combustion turbine. In so doing, we were able to evaluate comparably all of the proposals over the 40-year evaluation period.

Q: WERE ANY OTHER COST CONSIDERATIONS INCLUDED IN YOUR ANALYSIS?

A: Yes. For the PPA proposals, the analysis considered an equity cost. This was necessary because contracted resources are potentially subject to accounting lease treatment based on the term and conditions of the PPA. The PPA payment obligations can create accounting liabilities that adversely impact the Company's effective capital structure, with the extent of the impact depending on whether the lease constitutes a financial lease or an operating lease. In essence, the liability is treated like debt on the Company's balance sheet, thereby resulting in a decrease in the Company's equity ratio. Accordingly, the equity component included in the analysis reflected the cost to the Company to maintain the prior equity ratio and offset the negative impact caused by the lease treatment of the particular PPA under study.

For any proposal with capacity expected to be available to the Company prior to December 1, 2023, the evaluation ascribed a value for that capacity based on the economic carrying cost of a combustion turbine. Our evaluation also captured the capacity value associated with those proposals that offered additional capacity during the winter months.

Q: DID YOU CONSIDER ANY COST IMPACTS UNRELATED TO GENERATION?

A: Yes. As part of our evaluation, we factored in any costs or benefits associated with transmission system impacts resulting from a given proposal, as determined by SCS Transmission. Likewise, SCS Transmission evaluated the collective impact of the entire portfolio of resources.

Q: DID YOU PERFORM ONLY ONE SET OF ANALYSES?

A: No. Once a competitive tier of proposals had been identified, Alabama Power contacted the RFP respondents to obtain additional information, whether through refreshed pricing or further data associated with the submission. Any further data obtained by the Company that was pertinent to our analysis was incorporated into subsequent evaluations. In addition, the Barry Unit 8 proposal was updated to reflect adjusted pricing as well as a proposal for an additional unit. That unit did not make the short list of proposals, however, due to transmission investment that would have been necessary to accommodate the addition of the capacity.

Q: HOW WERE THE EVALUATIONS OF SOLAR BESS PROJECTS INCORPORATED INTO YOUR OVERALL EVALUATION?

A: As Mr. Kelley describes in his testimony, Alabama Power secured several proposals for Solar BESS projects in connection with the completion of its review of the Renewable RFP. As I noted earlier, Alabama Power performed the evaluations of those projects and then supplied the results to my group.

Q: DID YOU WORK WITH ALABAMA POWER ON ITS ANALYSIS OF THE SOLAR BESS PROJECTS?

A: Yes. I worked with the Forecasting and Resource Planning group to structure an analysis that, while not identical to the generation cost method that I described above, nonetheless captured the same cost components and yielded comparable results that could be incorporated into our analysis for overall comparison and evaluative purposes.

Q: HOW DID YOUR ANALYSIS ACCOUNT FOR FUTURE UNCERTAINTY REGARDING FUEL PRICES AND CARBON COSTS?

A: At the direction of the Company, we applied two additional assumptions to our analysis. First, we considered the potential that natural gas prices over the evaluation period could remain lower (i.e., lower gas, or “LG”) than our reference case assumption (i.e., moderate gas, or “MG”). Second, we considered the impact of a $20/per ton cost associated with any carbon emissions from the proposed resource option. These additional assumptions yielded a total of four evaluations: MG0, MG20, LG0, and LG20. Exhibit MBL-1 reflects the results of these evaluations.

Q: HOW DID YOU ESTABLISH THE FINAL RANKINGS FOR THE PORTFOLIO?

A: As Exhibit MBL-1 shows, the economics of each proposal (under each of the four scenarios) were captured on a net present value basis in terms of dollars per kilowatt ($/kW). Rather than favoring any particular scenario and biasing the outcome, the four were treated as of equal likelihood. The final ranking reflects an arithmetic average of the economics of each proposal under the four scenarios.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	)
	)
Petitioner	)

DIRECT TESTIMONY OF M. BRANDON LOONEY
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA	)
COUNTY OF JEFFERSON	)

M. Brandon Looney, being first duly sworn, deposes and says that he has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

M. Brandon Looney

Subscribed and sworn to before me
this 4th day of September, 2019.

ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

Notary Public

Direct Testimony of M. Brandon Looney

Exhibit MBL-1

PUBLIC VERSION

Alabama Power Capacity Resource Portfolio
Shortlist Economic Analysis Summary

Rank	Project	Project Type	Winter Capacity MW	Cumulative Capacity MW	Average NPV	$/kW NPV LG0	LG20	MG0	MG20
1	Dallas County Solar plus BESS	Storage PPA	68	68	-$40	$385	-$115	$19	-$450
2	Dothan Solar plus BESS	Storage PPA	68	136	-$39	$376	-$115	$22	-$440
3	Anniston Solar plus BESS	Storage PPA	68	204	-$30	$378	-$118	$26	-$406
4	Talladega Solar plus BESS	Storage PPA	68	272	$6	$418	-$67	$65	-$393
5	AL Solar C plus BESS	Storage PPA	68	340	$33	$477	-$59	$99	-$385
6	Barry Unit 8	Turnkey Build CC	743*	1,083	$157	$429	-$307	$523	-$16
7	Hog Bayou Energy Center (early 19Y PPA)	PPA CC	238	1,321	$410	$452	$60	$631	$498
8	Central Alabama Generating Station	APSA CC	915	2,236	$433	$519	$35	$696	$484
9	Alternate Project A	APSA CC	[redacted]		$444	$513	$39	$716	$508
10	Alternate Project B	PPA CC	[redacted]		$457	$495	$138	$659	$536
11	Alternate Project C	PPA CT	[redacted]		$463	$517	$270	$587	$481
12	Alternate Project D	PPA CT	[redacted]		$463	$517	$270	$587	$481
13	Alternate Project E	PPA CT	[redacted]		$489	$536	$298	$613	$509
14	Alternate Project F	PPA CC	[redacted]		$512	$575	$176	$726	$572
15	Alternate Project G	PPA CC	[redacted]		$546	$608	$200	$762	$615
16	Alternate Project H	PPA CC	[redacted]		$560	$619	$254	$754	$611
17	Alternate Project I	PPA CC	[redacted]		$581	$640	$268	$778	$640

Note:
* Capacity rating represents the Barry Unit 8 performance after the 48-month contractual upgrade that will result in an additional 17 MWs of capacity

Alabama Power Capacity Resource Portfolio
Shortlist Economic Analysis Details - LG0

Project Name	Summer Capacity Ratings MW	Winter Capacity Ratings MW	PPA Term or Remaining Life	Costs ($/kW)							Benefits ($/kW)					Total Project Cost/(Benefit) $/kW
				Capacity Cost	Fixed O&M	Equity Cost	Start-up Cost	Natural Gas FT	Term Equalization	Total Cost	Pre Dec 2023 Capacity Credit	Energy Savings	Winter Capacity	Avoided Transmission	Total Benefits	
Dothan Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**481**	[redacted]	[redacted]	[redacted]	[redacted]	**106**	**376**
Anniston Solar plus BESS	68	68	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**665**	[redacted]	[redacted]	[redacted]	[redacted]	**288**	**378**
Dallas County Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**509**	[redacted]	[redacted]	[redacted]	[redacted]	**124**	**385**
Talladega Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**493**	[redacted]	[redacted]	[redacted]	[redacted]	**75**	**418**
Barry Unit 8	685	743	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,220**	[redacted]	[redacted]	[redacted]	[redacted]	**792**	**429**
Hog Bayou Energy Center (early 19Y PPA)	222	238	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,096**	[redacted]	[redacted]	[redacted]	[redacted]	**644**	**452**
AL Solar C plus BESS	68	68	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**649**	[redacted]	[redacted]	[redacted]	[redacted]	**172**	**477**
Alternate Project B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,083**	[redacted]	[redacted]	[redacted]	[redacted]	**589**	**495**
Alternate Project A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**1,061**	[redacted]	[redacted]	[redacted]	[redacted]	**548**	**513**
Central Alabama Generating Station	890	915	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**987**	[redacted]	[redacted]	[redacted]	[redacted]	**469**	**519**
Alternate Project C	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**644**	[redacted]	[redacted]	[redacted]	[redacted]	**128**	**517**
Alternate Project D	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**644**	[redacted]	[redacted]	[redacted]	[redacted]	**128**	**517**
Alternate Project E	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**658**	[redacted]	[redacted]	[redacted]	[redacted]	**123**	**536**
Alternate Project F	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**867**	[redacted]	[redacted]	[redacted]	[redacted]	**292**	**575**
Alternate Project G	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**911**	[redacted]	[redacted]	[redacted]	[redacted]	**303**	**608**
Alternate Project H	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**854**	[redacted]	[redacted]	[redacted]	[redacted]	**235**	**619**
Alternate Project I	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**885**	[redacted]	[redacted]	[redacted]	[redacted]	**245**	**640**

Alabama Power Capacity Resource Portfolio
Shortlist Economic Analysis Details - LG20

Project Name	Summer Capacity Ratings MW	Winter Capacity Ratings MW	PPA Term or Remaining Life	Costs ($/kW)							Benefits ($/kW)					Total Project Cost/(Benefit) $/kW
				Capacity Cost	Fixed O&M	Equity Cost	Start-up Cost	Natural Gas FT	Term Equalization	Total Cost	Pre Dec 2023 Capacity Credit	Energy Savings	Winter Capacity	Avoided Transmission	Total Benefits	
Barry Unit 8	685	743	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,221	[redacted]	[redacted]	[redacted]	[redacted]	1,528	-307
Anniston Solar plus BESS	68	68	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	574	[redacted]	[redacted]	[redacted]	[redacted]	692	-118
Dothan Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	433	[redacted]	[redacted]	[redacted]	[redacted]	548	-115
Dallas County Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	461	[redacted]	[redacted]	[redacted]	[redacted]	576	-115
Talladega Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	445	[redacted]	[redacted]	[redacted]	[redacted]	512	-67
AL Solar C plus BESS	68	68	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	560	[redacted]	[redacted]	[redacted]	[redacted]	619	-59
Central Alabama Generating Station	890	915	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	902	[redacted]	[redacted]	[redacted]	[redacted]	867	35
Alternate Project A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	979	[redacted]	[redacted]	[redacted]	[redacted]	941	39
Hog Bayou Energy Center (early 19Y PPA)	222	238	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	993	[redacted]	[redacted]	[redacted]	[redacted]	933	60
Alternate Project B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	912	[redacted]	[redacted]	[redacted]	[redacted]	774	138
Alternate Project F	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	761	[redacted]	[redacted]	[redacted]	[redacted]	585	176
Alternate Project G	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	805	[redacted]	[redacted]	[redacted]	[redacted]	605	200
Alternate Project H	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	679	[redacted]	[redacted]	[redacted]	[redacted]	425	254
Alternate Project I	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	710	[redacted]	[redacted]	[redacted]	[redacted]	442	268
Alternate Project C	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	471	[redacted]	[redacted]	[redacted]	[redacted]	201	270
Alternate Project D	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	471	[redacted]	[redacted]	[redacted]	[redacted]	201	270
Alternate Project E	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	465	[redacted]	[redacted]	[redacted]	[redacted]	166	298

Alabama Power Capacity Resource Portfolio
Shortlist Economic Analysis Details - MG0

Project Name	Summer Capacity Ratings MW	Winter Capacity Ratings MW	PPA Term or Remaining Life	Costs ($/kW) Capacity Cost	Fixed O&M	Equity Cost	Start-up Cost	Natural Gas FT	Term Equalization	Total Cost	Benefits ($/kW) Pre Dec 2023 Capacity Credit	Energy Savings	Winter Capacity	Avoided Transmission	Total Benefits	Total Project Cost/(Benefit) $/kW
Dallas County Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	510	[redacted]	[redacted]	[redacted]	[redacted]	492	19
Dothan Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	483	[redacted]	[redacted]	[redacted]	[redacted]	461	22
Anniston Solar plus BESS	68	68	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	668	[redacted]	[redacted]	[redacted]	[redacted]	642	26
Talladega Solar plus BESS	68	68	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	495	[redacted]	[redacted]	[redacted]	[redacted]	429	65
AL Solar C plus BESS	68	68	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	652	[redacted]	[redacted]	[redacted]	[redacted]	553	99
Barry Unit 8	685	743	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,224	[redacted]	[redacted]	[redacted]	[redacted]	700	523
Alternate Project C	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	656	[redacted]	[redacted]	[redacted]	[redacted]	69	587
Alternate Project D	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	656	[redacted]	[redacted]	[redacted]	[redacted]	69	587
Alternate Project E	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	680	[redacted]	[redacted]	[redacted]	[redacted]	67	613
Hog Bayou Energy Center (early 19Y PPA)	222	238	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,101	[redacted]	[redacted]	[redacted]	[redacted]	470	631
Alternate Project B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,094	[redacted]	[redacted]	[redacted]	[redacted]	435	659
Central Alabama Generating Station	890	915	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	996	[redacted]	[redacted]	[redacted]	[redacted]	300	696
Alternate Project A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,077	[redacted]	[redacted]	[redacted]	[redacted]	361	716
Alternate Project F	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	872	[redacted]	[redacted]	[redacted]	[redacted]	146	726
Alternate Project H	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	866	[redacted]	[redacted]	[redacted]	[redacted]	111	754
Alternate Project G	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	915	[redacted]	[redacted]	[redacted]	[redacted]	154	762
Alternate Project I	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	896	[redacted]	[redacted]	[redacted]	[redacted]	118	778

Alabama Power Capacity Resource Portfolio
Shortlist Economic Analysis Details - MG20

Project Name	Summer Capacity Ratings MW	Winter Capacity Ratings MW	PPA Term or Remaining Life	Costs ($/kW) Capacity Cost	Fixed O&M	Equity Cost	Start-up Cost	Natural Gas FT	Term Equalization	Total Cost	Benefits ($/kW) Pre Dec 2023 Capacity Credit	Energy Savings	Winter Capacity	Avoided Transmission	Total Benefits	Total Project Cost/(Benefit) $/kW
Dallas County Solar plus BESS	68	68	28	[redacted]						483	[redacted]				933	-450
Dothan Solar plus BESS	68	68	28	[redacted]						456	[redacted]				896	-440
Anniston Solar plus BESS	68	68	20	[redacted]						617	[redacted]				1,024	-406
Talladega Solar plus BESS	68	68	28	[redacted]						468	[redacted]				861	-393
AL Solar C plus BESS	68	68	20	[redacted]						603	[redacted]				988	-385
Barry Unit 8	685	743	40	[redacted]						1,224	[redacted]				1,240	-16
Central Alabama Generating Station	890	915	24	[redacted]						949	[redacted]				466	484
Alternate Project C	[redacted]									579	[redacted]				98	481
Alternate Project D	[redacted]									579	[redacted]				98	481
Hog Bayou Energy Center (early 19Y PPA)	222	238	19	[redacted]						1,038	[redacted]				540	498
Alternate Project A	[redacted]									1,029	[redacted]				521	508
Alternate Project E	[redacted]									594	[redacted]				84	509
Alternate Project B	[redacted]									1,018	[redacted]				482	536
Alternate Project F	[redacted]									808	[redacted]				236	572
Alternate Project H	[redacted]									788	[redacted]				177	611
Alternate Project G	[redacted]									852	[redacted]				237	615
Alternate Project I	[redacted]									819	[redacted]				179	640

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**	**PETITION**
	)	
Petitioner	**)**	
	)	**Docket No. ________**

DIRECT TESTIMONY OF CHRISTINE M. BAKER
ON BEHALF OF ALABAMA POWER COMPANY

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Christine Baker. I currently serve as the Director of Regulatory Pricing & Costing Services for Alabama Power Company ("Alabama Power" or "Company"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I graduated from Auburn University in 1993 with a Bachelor of Industrial Engineering degree. I began my career at Alabama Power in 1994 in the Marketing department. I progressed through various areas including Load Research and Pricing becoming a Team Leader in Pricing in 2005 and the Manager of Pricing and Costing in 2012. I assumed my current role as Director in 2014.

Q: DESCRIBE YOUR PROFESSIONAL RESPONSIBILITIES AS DIRECTOR OF REGULATORY PRICING & COSTING SERVICES.

A: As Director, my responsibilities involve oversight of the Company's pricing and costing functions. The former includes the design, modification and administration of all available customer rate schedules; the latter includes the annual cost of service study and associated load research along with various costing analyses that support the pricing options offered to customers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to describe the timing and manner by which costs associated with the proposed generating resources reflected in the Company's petition for a certificate of convenience and necessity will be recovered if the Company is granted the requested authorization.

Q. ARE THERE EXISTING RETAIL RATE MECHANISMS THAT INFORM THE MANNER OF COST RECOVERY, IF THE REQUESTED AUTHORIZATION IS GRANTED?

A: Yes. Alabama Power has on file with the Alabama Public Service Commission ("Commission") rate mechanisms that apply to the cost recovery of the projects identified in the petition. These include Rate CNP – Adjustment for Commercial Operation of Certificated New Plant ("Rate CNP"); Rate ECR – Energy Cost Recovery Rate ("Rate ECR"); and Rate RSE – Rate Stabilization and Equalization Factor ("Rate RSE"). Copies of these rates are attached to my testimony at Exhibit CMB-1.

Q. HOW DOES THE COMPANY DETERMINE WHICH COST RECOVERY MECHANISM TO APPLY?

A: Each of the foregoing rates has terms and conditions that govern its application relative to the projects proposed for certification. The Company also relies on direction from the Commission as to the recovery of certain costs through either Rate CNP or Rate ECR; as to the selection of an allocation formula when required; or in the event certain accounting authorizations are necessary.

Q. CAN YOU EXPAND ON THE PROVISIONS OF THE RATES AND HOW THEY OPERATE?

A: Rate CNP prescribes the manner for cost recovery of certificated new plant, power purchase arrangements ("PPA") and certain mandated expenditures. Rate CNP is divided into three parts. Part A (the CNP Factor for Certificated Generating Facilities, or "Plant Factor") addresses the non-mandated costs associated with newly certificated generating resources built or acquired by Alabama Power. Part B (the CNP Factor for Certificated Power Purchase Arrangements, or "Purchase Factor") addresses certain Commission-directed costs associated with certificated PPAs. Part C (the CNP Factor for Compliance with Governmental Mandates, or "Compliance Factor") addresses costs incurred due to defined governmental mandates associated with each of the certificated resources.

Rate ECR provides for cost recovery, through an Energy Cost Recovery Factor ("ECR Factor") of defined energy-related costs associated with the certificated projects (e.g., fuel costs), along with any other costs or credits that are a part of, or directly related to, a certificated PPA, as directed by the Commission.

Rate RSE provides for the rate treatment of general costs not otherwise captured above, arising from the authorization being sought through the Company's petition.

Q. HOW WILL THESE COST RECOVERY MECHANISMS APPLY TO EACH OF THE PROPOSED RESOURCES?

A: I will start with the Barry Unit 8 project, which is discussed in detail in the testimony of Mr. Bush. For Barry Unit 8, a specified portion of the associated cost recovery would be incorporated pursuant to Rate CNP Part A. The CNP Plant Factor would initiate the recovery of costs effective for billings starting with the second calendar month after commercial operation of the facility, which is targeted for November 1, 2023. Thereafter, the revenues derived from this initial factor and the associated costs would be reflected in the Company's annual filing under Rate RSE. The amount of the CNP Plant Factor would include the revenue requirement for the average retail net plant balance, excluding any portion attributable to compliance with governmental mandates recoverable under the CNP Compliance Factor. The factor also would include the retail portion of the plant's operation, maintenance and depreciation expenses, excluding those expenses recoverable under Rate ECR and the CNP Compliance Factor. This total retail revenue requirement would then be allocated to the respective rate schedules subject to Rate CNP in accordance with the allocation formula selected by the Commission. In this respect, the Company is requesting that the Commission specify use of the Revenue Allocation formula, consistent with Paragraph (8) of Rate CNP Part A, as the facility is being certificated based on a capacity need. I would also note here that the Company would expect to record construction work in progress costs incurred prior to the issuance of an order on certification to meet the targeted in-service date. The Company intends to submit a discrete proposal respecting such recovery in the coming weeks.

Q. YOU REFERENCED CERTAIN COSTS BEING EXCLUDED FROM THE DEVELOPMENT OF THE CNP PLANT FACTOR. CAN YOU ELABORATE ON THESE EXCLUSIONS?

A: The reasonably identifiable costs of the Barry Unit 8 facility attributable to compliance with governmental mandates (e.g., the unit's cooling tower and selective catalytic reduction) and the associated operating and maintenance expenses would be recovered through the CNP Compliance Factor. The annual filing of the CNP Compliance Factor would include the revenue requirement for the average retail net plant balance attributable to compliance with governmental mandates, plus the associated retail portion of the plant's operation, maintenance and depreciation expenses, all for the applicable compliance year. The total retail revenue requirement for the compliance year would then be allocated to the respective rate schedules according to the revenue allocation formula set forth in Rate CNP Part C. Finally, all associated energy costs, as defined by Rate ECR, would be recoverable in accordance with the rate.

Q. DOES THAT COMPLETE THE DESCRIPTION OF COST RECOVERY FOR THE PROPOSED BARRY UNIT 8?

A: Yes.

Q. PLEASE DESCRIBE THE COST RECOVERY PROCESS FOR THE PROPOSED ACQUISITION OF THE CENTRAL ALABAMA GENERATING STATION?

A: Upon closing of the acquisition (which is targeted for mid-2020), Alabama Power will assume an existing power sales agreement under which the full output of the facility remains committed to a third-party until May 2023. With the entirety of the plant so committed, Rate CNP Part A would not need to operate until that power sales agreement terminates. Accordingly, the Company requests that the effective date of the CNP Plant Factor be postponed from 2020 until the existing power sales agreement term ends in May 2023. The Company also would request that the Commission authorize it to depreciate or amortize, as appropriate, the total cost associated with the acquisition as of the closing over the entire life of the facility and establish any required regulatory assets. This accounting treatment will result in an alignment of the entire cost of the acquisition with the full benefits that customers will realize from the addition of capacity and increased reliability over the complete period of its service to customers.

Q: HOW DOES THE COMPANY PROPOSE TO TREAT THE ACQUSITION DURING THE INTERIM PERIOD?

A: Given the Company's requested postponement of the effective date of the CNP Plant Factor, the acquisition costs, along with the revenues associated with the power sales agreement, would flow through Rate RSE during the interim three-year period. As the revenues associated with the power sales agreement are expected to more than offset the acquisition costs during this time, this will result in downward pressure on customer rates.

Q: WHAT WOULD TRANSPIRE FOLLOWING THE END OF THE INTERIM PERIOD?

A: Once the power sales agreement has ended, the CNP Plant Factor would become effective in June 2023, in accordance with the provisions of Rate CNP Part A. The amount of the CNP Plant Factor would include the revenue requirements on amounts allocated to retail associated with the average of acquisition costs, net of amortization and depreciation and net changes to plant assets, determined in accordance with the rate and consistent with the factor's June 2023 effective date. The revenue requirement for the CNP Plant Factor would exclude any reasonably identifiable portion of the average retail net plant balance attributable to components of the plant required for compliance with governmental mandates recoverable under the CNP Compliance Factor. The CNP Plant Factor also will include the retail portion of the plant's operation, maintenance and depreciation expenses, excluding those expenses recoverable under Rate ECR and not otherwise recoverable through the CNP Compliance Factor. This total retail revenue requirement for the upcoming 12 months would then be allocated to the respective rate schedules subject to Rate CNP in accordance with the allocation formula selected by the Commission in its order certificating the plant. In this respect, and consistent with its request for Barry Unit 8, the Company is requesting that the Commission specify the Revenue Allocation formula.

Q. DOES THAT COMPLETE THE INCORPORATION OF COST RECOVERY FOR THE PROPOSED ACQUISITION OF THE CENTRAL ALABAMA GENERATING STATION?

A: No. Beginning in June of 2023, the reasonably identifiable portions of the plant attributable to compliance with governmental mandates (e.g., cooling tower, certain catalysts), along with the associated operating, maintenance and depreciation expenses, will be recovered through the CNP Compliance Factor, in the same manner as I described above for Barry Unit 8. In addition to the compliance costs, all fuel costs associated with the operation of the plant beginning in June of 2023 would be incorporated into the Energy Cost Recovery Factor through the terms of Rate ECR. During the interim period, fuel costs are borne by the purchaser being served under the power sales agreement.

Q. HOW WILL THE COMPANY INCORPORATE THE COSTS ASSOCIATED WITH THE PROPOSED PPAS?

A: The costs associated with the PPAs will be recovered pursuant to the terms of both Rate CNP Part B through the CNP Purchase Factor and Rate ECR through the purchased energy portion of the Energy Cost Recovery Factor. The Commission will specify which costs will be included under each of these rates. As the terms of the PPAs vary (one PPA concerning the output of the Hog Bayou Energy Center ("Hog Bayou") and five PPAs regarding the output from the solar/battery energy storage systems ("Solar/BESS") projects), the Commission will specify which costs will be included under each of these rates. In addition, the PPAs create an equity cost as discussed in Mr. Looney's testimony. The Company would request that the Commission confirm the inclusion of such costs as recoverable through Rate RSE.

Q: DESCRIBE HOW THE HOG BAYOU PPA WILL BE TREATED.

With respect to the Hog Bayou PPA, the applicable costs for incorporation into rates include capacity and energy costs under the PPA, along with any other costs and credits that may arise under the terms and conditions. The Company is requesting that the Commission specify all capacity-related costs (i.e., the capacity payments) associated with the PPA be recovered under the terms of the CNP Purchase Factor. The retail revenue requirement for the CNP Purchase Factor year will be allocated to the respective rate schedules in accordance with the revenue allocation formula set forth in Rate CNP Part B. The Hog Bayou PPA is scheduled to commence contemporaneously with certification. If the certificate is obtained prior to the February 1, 2020 filing date under Rate CNP Part B for the upcoming Purchase Factor year, the Company would reflect these costs in that filing. If the certificate is issued after the February 1, 2020 filing date, the Company would elect to include the cost in the recovery balance, to be reflected in the next scheduled Purchase Factor year as allowed by Rate CNP Part B. The Company is also requesting that the Commission specify the recovery of the Hog Bayou PPA energy-related costs (e.g., energy payments, variable operation and maintenance expenses, fuel costs) in accordance with the provisions of Rate ECR and the Energy Cost Recovery Factor.

Q. WILL THE COSTS FOR THE FIVE SOLAR/BESS PPAS BE INCORPORATED IN THE SAME MANNER?

A: These PPAs have varying start dates from 2022 through 2024, but the payment structure is the same: a bundling of both solar- and BESS-related costs into a combined energy payment, without specific delineation. As Mr. Kelley explains in his testimony, however, the BESS component of each project provides capacity to the Company. Based on the Company's analysis, 38 percent of the combined energy payments associated with the Solar/BESS PPAs are reasonably attributable to the cost of the BESS. Accordingly, the Company is requesting that the Commission specify that 38 percent of the Solar/BESS payments be directed for recovery through the CNP Purchase Factor, with the remainder recovered pursuant to the terms of the Energy Cost Recovery Factor as energy-related payments are incurred. The Solar/BESS expenses directed to the CNP Purchase Factor for the applicable Purchase Factor year in which the PPA commences will be reflected in an appropriate Replacement Factor, as required under the rate, and allocated to the respective rate schedules according to the revenue allocation formula as set forth in Rate CNP Part B. Lastly, the Company would recover costs associated with interconnecting the projects to the Company's electric system under Rate RSE.

Q: WHAT DOES THE COMPANY INTEND TO DO WITH RENEWABLE ENERGY CERTIFICATES ("RECS") ASSOCIATED WITH THE SOLAR/BESS PROJECTS?

A: As with other projects that generate RECs, the Company has reserved the right to retire the RECs on behalf of customers or make sales of RECs to its customers or to other third parties. Any revenues associated with REC sales would be credited to Rate ECR to the benefit of customers.

Q. DOES THE FOREGOING DISCUSSION ADDRESS THE RATE TREATMENT FOR ALL OF THE SUPPLY-SIDE RESOURCES BEING PROPOSED?

A: Yes.

Q. WHAT ARE THE ESTIMATED RATE PRESSURES OF THE PROPOSED PLAN?

A: Assuming certification of the proposed resources in 2020, the associated costs and estimated fuel savings would be incorporated into rates through the various rate mechanisms described and over the timeframes I have discussed. Any necessary adjustments would occur over an approximately four-year period, with specific actions corresponding with the time-frame under which the resources and PPAs are brought into service. Once all supply-side resources are in service, the Company estimates that the net pressure on rates through the various mechanisms would equate to approximately $4 per month on a typical residential bill. This estimated impact takes into account both the cost of the new resources as well as energy savings (primarily fuel savings) expected to result as these additions are used to displace higher-cost output from other facilities.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

ALABAMA POWER COMPANY	**)**
	)
Petitioner	**)**

DIRECT TESTIMONY OF CHRISTINE M. BAKER
ON BEHALF OF ALABAMA POWER COMPANY

STATE OF ALABAMA	)
COUNTY OF JEFFERSON	)

Christine M. Baker, being first duly sworn, deposes and says that she has read the foregoing prepared testimony and that the matters and things set forth therein are true and correct to the best of her knowledge, information and belief.

Christine M. Baker

Christine M. Baker

Subscribed and sworn to before me
this 4th day of September, 2019.

ALABAMA NOTARY PUBLIC
ESTHER T. HOWARD
NOTARY PUBLIC
STATE OF ALABAMA
COMM. EXP. 05-12-2020

Notary Public

Direct Testimony of Christine M. Baker

Exhibit CMB-1

RATE CNP
ADJUSTMENT FOR COMMERCIAL OPERATION OF CERTIFICATED NEW PLANT

By order of the Alabama Public Service Commission dated March 9, 2017 in Dockets #18117 and #18416.

Effective March 23, 2017 for application to April, 2017 billings and thereafter.

AVAILABILITY

Same as the specific rate incorporating this Rate CNP by reference.

APPLICABILITY

Applicable as an integral part of each rate schedule of the Company in which reference is made to this Rate CNP.

EXPLANATORY STATEMENT

Rate CNP is designed to adjust monthly billings to recover certain costs associated with: (i) a generating facility developed by the Company, or the acquisition of a generating facility by the Company, for which a certificate of convenience and necessity has been issued by the Alabama Public Service Commission; and (ii) a power purchase arrangement for which a certificate of convenience and necessity has been issued by the Alabama Public Service Commission; and (iii) compliance with laws, regulations, or other such governmental mandates impacting the Company's facilities or operations. The billing mechanism to recover such costs is hereinafter referred to as the "CNP Adjustment", and comprises the CNP Plant Factor, the CNP Purchase Factor, and the CNP Compliance Factor. Rate CNP is made a part of each of the rate schedules of the Company to which Rate CNP is applicable and any modification, amendment or replacement of such rate schedules. All bills rendered under such rate schedules of the Company will be subject to the CNP Adjustment.

DERIVATION OF CNP ADJUSTMENT

The CNP Adjustment to be applied to each kilowatt-hour in the affected monthly billings shall be the CNP Factor associated with certificated generating facilities (as described in Subpart A below), the CNP Factor associated with certificated power purchase arrangements (as described in Subpart B below), and the CNP Factor associated with governmental mandates (as described in Subpart C below). Those factors shall be derived as follows:

A. CNP FACTOR FOR CERTIFICATED GENERATING FACILITIES

The CNP Factor associated with certificated generating facilities ("CNP Plant Factor") is a factor intended to initiate the recovery of costs associated with additional generating facilities that have been certificated by the Commission, whether developed or acquired by the Company ("Certificated Plant"). Thereafter, the revenues derived from this initial factor and the costs associated with the new generating facility will be reflected in the Company's annual filing under Rate RSE. The amount of this CNP Plant Factor shall be determined by the following steps:

(1) Projected electric plant in service balances associated with the Certificated Plant (excluding any reasonably identifiable portion of such balances attributable to compliance with governmental mandates, which portion is recoverable pursuant to Part C) will be determined for the upcoming twelve (12) month period, beginning with the month immediately following the month in which commercial operation commences or the acquisition closes, as applicable ("Plant Factor Year"). For an acquisition, the additions to electric plant in service shall be the Company's capital investment to acquire the facility, as approved in the Commission's certification order.

(2) The plant balances calculated in Item (1), less (a) any projected balance of associated accumulated depreciation and (b) any projected balance of associated accumulated deferred income taxes for the upcoming twelve (12) month period in accordance with the rules and requirements of the Internal Revenue Service, will be summed and divided by twelve (12) to derive the average net plant balance. The average net plant balance (less any portion of that balance associated with unit power sales agreements or other wholesale power arrangements of a similar nature) will then be separated to retail electric service by application of the retail electric investment factor set forth in the most recent cost-of-service study filed by the Company with the Commission to derive the "average retail net certificated plant balance".

(3) The weighted cost of capital shall be determined by using the embedded costs of debt and preferred stock for the month in which commercial operation of the certificated plant commences or, for an acquisition, the month in which the transaction closes. Weighting shall be accomplished by applying the corresponding capital structure ratios. For purposes of this calculation, the weighted cost of common equity component shall be the "adjusting point" of the WRRCE under Rate RSE including any applicable performance-based adder. In the absence of such an adjusting point, the weighted cost of common equity component shall be based on the allowed rate of return on common equity as then reflected in the most recent rate order of the Commission. To the extent investments attributable to the certificated plant are eligible for tax exempt financing, the amount of facilities financed at the tax exempt rates will be reflected at the embedded tax exempt rate(s) and the balance of investments financed by taxable debt will utilize the Company's embedded cost of debt, excluding tax exempt debt.

(4) The income tax requirement associated with the preferred stock and common equity weighted cost of capital shall be determined by the formula: [combined tax rate ÷ (1 - combined tax rate)] X (preferred stock weighted cost + common equity weighted cost). The combined tax rate shall be calculated as

$$T = \frac{F + S - 2FS}{1 - FS}$$

where "F" is the statutory Federal income tax rate and "S" is the statutory State income tax rate.

(5) The revenue requirement for the average retail net certificated plant balance will be computed by the multiplication of Item (2) above times the total of Items (3) and (4) above.

(6) Projected operation and maintenance expenses and depreciation expense associated with the Certificated Plant (excluding fuel, which is recoverable pursuant to Rate ECR, and any reasonably identifiable portion of such expenses attributable to compliance with governmental mandates, which portion is recoverable pursuant to Part C) will be determined for the Plant Factor Year. These expenses (less any portion of the expenses associated with unit power sales agreements or other wholesale power arrangements of a similar nature directly related to the facility) will then be separated to retail electric service by application of the retail expense allocation factor set forth in the most recent cost-of-service study filed by the Company with the Commission.

(7) The "retail revenue requirement" ("RRR") will be computed by the addition of Items (5) and (6) above.

(8) The retail revenue requirement (Item (7) above) will be allocated to each of the respective rate schedules that are subject to this Rate CNP in accordance with one of the formulas set out below, and will be applied to that rate schedule so as to adjust the kilowatt-hour charges thereunder. The Commission will specify the applicable allocation formula in its order certificating the new generating facility or acquisition.

ALLOCATION FORMULA

Option (i): Energy Allocation

$$\frac{(RRR)}{kWh_t} = \text{CNP Plant Factor}$$

Option (ii): Revenue Allocation

$$\frac{(RRR)\ \dfrac{BR_s}{BR_t}}{kWh_s} = \text{CNP Plant Factor}$$

Where, for the Plant Factor Year:

RRR = Retail revenue requirement.

BR_s = The projected base rate revenue from each respective rate schedule that is subject to this Rate CNP for the Plant Factor Year. “Base rate revenue” from any such rate schedule excludes amounts from Rate ECR and Rate T.

BR_t = The projected total base rate revenues from all rate schedules that are subject to this Rate CNP for the Plant Factor Year. Such base rate revenues exclude amounts from Rate ECR and Rate T.

kWh_s = The projected kilowatt-hour sales by rate schedule for the Plant Factor Year.

kWh_t = The projected total kilowatt-hour sales for the Plant Factor Year.

The resulting amount (rounded to the nearest .0001 cent) shall be the CNP Plant Factor for that respective rate schedule.

B. CNP FACTOR FOR CERTIFICATED POWER PURCHASE ARRANGEMENTS

The CNP Factor associated with power purchase arrangements (“CNP Purchase Factor”) is based upon the costs as specified for inclusion by the Commission in the respective orders granting certification. The amount of the CNP Purchase Factor shall be determined by the following steps:

(1) The estimated cost of all such purchases (excluding the energy cost recoverable through Rate ECR and any other costs directed for recovery elsewhere by the Commission) will be projected for the twelve (12) month period from April 1 through March 31 (“Purchase Factor Year”).

(2) The amount from Item (1) will be separated to retail electric service by application of the retail expense allocation factor set forth in the most recent cost-of-service study filed by the Company with the Commission.

(3) The amount of any over-recovered or under-recovered balance will be projected for the end of the immediately preceding Purchase Factor Year.

(4) The "retail revenue requirement" will be computed by the addition of Items (2) and (3) above.

(5) The retail revenue requirement (Item (4) above) will be allocated to each of the respective rate schedules that are subject to this Rate CNP in accordance with the formula set out below and will be applied to that rate schedule so as to adjust the kilowatt-hour charges thereunder.

ALLOCATION FORMULA

$$\frac{(RRR)\ \frac{BR_s}{BR_t}}{kWh_s} = \text{CNP Purchase Factor}$$

Where, for the Purchase Factor Year:

RRR = Retail revenue requirement.

BR_s = The projected base rate revenue from each respective rate schedule that is subject to this Rate CNP for the Purchase Factor Year. "Base rate revenue" from any such rate schedule excludes amounts from Rate ECR and Rate T.

BR_t = The projected total base rate revenues from all rate schedules that are subject to this Rate CNP for the Purchase Factor Year. Such base rate revenues exclude amounts from Rate ECR and Rate T.

kWh_s = The projected kilowatt-hour sales by rate schedule for the Purchase Factor Year.

The resulting amount (rounded to the nearest .0001 cent) shall be the CNP Purchase Factor for that respective rate schedule.

C. <u>CNP FACTOR FOR COMPLIANCE WITH GOVERNMENTAL MANDATES</u>

The CNP factor associated with governmental mandates ("CNP Compliance Factor") is based upon the cost of compliance with: (i) environmental laws, regulations, and/or other mandates having a similar purpose ("environmental mandates"); and (ii) laws, regulations and/or other mandates directed to the utility industry involving security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations ("other mandates"). The amount of the CNP Compliance Factor shall be determined by the following steps:

(1) Projected in service plant balances associated with capital additions to certificated generating facilities, or other capital additions, as made necessary to comply with governmental mandates will be determined for the upcoming twelve (12) month period from January 1 to December 31 ("compliance cost year").

(2) The plant balances calculated in Item (1) (less (a) any projected balance of associated accumulated depreciation, (b) any projected balance of associated accumulated deferred income taxes, and (c) any projected balance of accumulated tax credits) will be summed and divided by twelve (12) to derive the "average net compliance plant balance" ("average plant balance"). The average plant balance (less any portion of that balance associated with unit power sales agreements or other wholesale power arrangements of a similar nature) will then be separated to retail electric service by application of jurisdictional separation factors set forth in the most recent cost-of-service study filed by the Company with the Commission to derive the "average retail net compliance plant balance" ("average retail plant balance").

(3) The weighted cost of capital shall be determined by use of the embedded costs of debt and preferred stock as of September 30 prior to the compliance cost year and weighting shall be accomplished by applying the capital structure ratios then prevailing. For purposes of this calculation, the weighted cost of common equity component shall be the "adjusting point" of the WRRCE under Rate RSE including any applicable performance-based adder. In the absence of such an adjusting point, the weighted cost of common equity component shall be based on the allowed rate of return on common equity as then reflected in the most recent rate order of the Commission. To the extent investments attributable to these governmental mandates become eligible for tax exempt financing, the amount of facilities financed at the tax exempt rates will be reflected at the embedded tax exempt rate(s) and the balance of investments financed by taxable debt will utilize the embedded cost of debt excluding the tax exempt debt.

(4) The income tax requirement associated with the preferred stock and common equity weighted cost of capital shall be determined by the formula: [combined tax rate ÷ (1 –

combined tax rate)] X (preferred stock weighted cost plus common equity weighted cost). The combined tax rate shall be calculated as

$$T = \frac{F + S - 2FS}{1 - FS}$$

Where “F” is the statutory Federal income tax rate and “S” is the statutory State income tax rate.

(5) The revenue requirement for the average retail plant balance will be computed by the multiplication of Item (2) above times the total of Items (3) and (4) above.

(6) Projected operation and maintenance expenses and depreciation expense that are attributable to governmental mandates will be determined for the compliance cost year. These expenses (less any portion of the expenses associated with unit power sales agreements or other wholesale power arrangements of a similar nature) will then be separated to retail electric service by application of the expense jurisdictional separation factor set forth in the most recent cost-of-service study filed by the Company with the Commission.

(7) The amount of any over-recovery or under-recovery (“true-up calculation”) will be determined with respect to Items (5) and (6) above based upon the actual average retail plant balance, actual expenses, actual depreciation expense, and actual retail kilowatt-hours, as opposed to the projections of these inputs that were used to derive the CNP Compliance Factor. The true-up calculation will be performed for the current compliance cost year using actual data through September 30 and projections of the inputs for the remainder of the calendar year. A true-up calculation will also be performed for the period of October 1 through December 31 of the prior compliance cost year, together with other appropriate adjustments to reflect actual data to the extent practicable.

(8) The “retail revenue requirement” (“RRR”) will be computed by the addition of Items (5), (6) and (7) above.

(9) The retail revenue requirement from Item (8) above will be allocated to each of the respective rate schedules that are subject to this Rate CNP in accordance with the formula set out below and will be applied to that schedule so as to adjust the kilowatt-hour charges thereunder.

RATE CNP
ADJUSTMENT FOR COMMERCIAL OPERATION OF CERTIFICATED NEW PLANT

By order of the Alabama Public Service Commission dated March 9, 2017 in Dockets #18117 and #18416.

Effective March 23, 2017 for application to April, 2017 billings and thereafter.

PAGE	EFFECTIVE DATE	REVISION
8 of 11	**March 23, 2017**	**Seventh**

ALLOCATION FORMULA

$$\frac{(RRR)\ \frac{BR_s}{BR_t}}{kWh_s} = \text{CNP Compliance Factor}$$

Where, for the compliance cost year,

RRR = Retail revenue requirement.

BR_s = The projected base rate revenue from each respective rate schedule that is subject to this Rate CNP for the upcoming compliance cost year. “Base rate revenue” from any such rate schedule excludes amounts from Rate ECR and Rate T.

BR_t = The projected total base rate revenues from all rate schedules that are subject to this Rate CNP for the upcoming compliance cost year. Such base rate revenues exclude amounts from Rate ECR and Rate T.

kWh_s = The projected kilowatt-hour sales by rate schedule for the upcoming compliance cost year.

The resulting amount (rounded to the nearest .0001 cent) shall be the CNP Compliance Factor for that respective rate schedule.

APPLICABLE CNP ADJUSTMENT

The CNP Plant Factor, the CNP Purchase Factor, and the CNP Compliance Factor shall become effective as follows:

(1) With respect to the CNP Plant Factor determined pursuant to Subpart A of this Rate CNP:

(a) For each rate schedule subject to this Rate CNP, the Company will file with the Commission the CNP Plant Factor (along with appropriate supporting materials) to be separately applied to each kilowatt-hour thereunder. This filing will be made on or before the first business day of the month following the month in which the applicable event described below occured.

i. For filings related to certificated plant developed by the Company, the event is commercial operation.

ii. For filings related to a certificated acquisition of an operational facility, the event is the closing of the acquisition.

iii. For filings related to a certificated acquisition of a facility still under construction, the event is the closing of the acquisition or commercial operation, whichever is later.

(b) The CNP Plant Factor filed by the Company will be effective for billings starting with the second calendar month following the occurrence of the applicable event, and shall remain in effect thereafter. Each CNP Plant Factor shall be incorporated in the charge for each kilowatt-hour under each of the rate schedules that are subject to this Rate CNP.

(c) The Company will make relevant books and records available for inspection by the Commission Staff as needed to resolve any questions concerning the development of any CNP Plant Factor hereunder. With respect to Company generating facilities under construction, the Company will provide the Commission Staff with monthly status reports. Reasonable arrangements will be made to preserve the confidentiality of any competitively-sensitive or proprietary data that is made available or accessed through such reports or during any such inspection.

(2) With respect to the CNP Purchase Factor determined pursuant to Subpart B of this Rate CNP:

(a) By February 1 of each year, the Company will file with the Commission a CNP Purchase Factor (along with appropriate supporting materials) for each rate schedule to be separately applied to each kilowatt-hour under each such rate schedule that is subject to this Rate CNP. In the event a certificated power purchase will begin or end during the projected twelve (12) month period (April 1 through March 31), the Company will also include in its filing a “replacement factor” that recognizes the effect of such new or terminated purchase.

(b) The CNP Purchase Factor filed by February of a given year will be effective for April billings of that year and will continue in effect through March billings of the following year; provided, however, that in the event the Company’s filing includes a replacement factor, that replacement factor will become effective for the billing month immediately following the month in which the certificated power purchase begins or terminates (in lieu of the initial factor) and will continue in effect for billings through the following March.

(c) In the event a power purchase that will begin during the projected twelve (12) month period is certificated by the Commission after the CNP Purchase Factor is filed, the Company may either: (i) file a new CNP Purchase Factor that recognizes the effect of the newly-certificated power purchase; or (ii) include the cost associated with that purchase in the balance described in Item (3) until such purchase can be reflected in Item (1) of the next scheduled CNP Purchase Factor calculation. Unanticipated terminations or other such events will be handled in the same manner.

(d) The Company will make relevant books and records available for inspection by the Staff as needed in order to resolve any questions from the Commission or its Staff concerning application of any CNP Purchase Factor developed hereunder. Reasonable arrangements will be made to preserve the confidentiality of any competitively-sensitive or proprietary data that is accessed during any such inspection.

(e) In the event this Rate CNP is terminated or withdrawn, the CNP Purchase Factor (including related true-ups) shall nevertheless continue to operate until all previously certificated power purchase arrangements have expired or otherwise been terminated in accordance with their terms.

(3) With respect to the CNP Compliance Factor determined pursuant to Subpart C of this Rate CNP:

(a) For each rate schedule subject to this Rate CNP, the Company will file with the Commission, by December 1 of each year, the CNP Compliance Factor (along with appropriate supporting materials) to be separately applied to each kilowatt-hour thereunder.

(b) Each CNP Compliance Factor filed by December 1 of a given year will be effective for January billings of the next succeeding year and will continue in effect through December billings of that same year.

(c) Subsequent to the filing of each CNP Compliance Factor, an informal meeting will be convened on the second Tuesday in December, as designated by the Commission, in order to review and discuss the Company's environmental compliance activities. At this meeting, the Company will provide an overview of its environmental compliance plan for the next five (5) years, together with the estimated cost associated with the implementation of that plan. The Company will also discuss pending environmental laws, regulations or other mandates relevant to its environmental compliance activities, as well as any other matters or information that it or the Commission considers relevant and appropriate in that regard. The Company will file the above-referenced environmental compliance plan at least thirty (30) days prior to the December 1 deadline for filing the CNP Compliance Factors described in Item 3(a) above.

(d) The Company will make relevant books and records available for inspection by the Commission Staff as needed to resolve any questions concerning the Company's environmental compliance plan and the development of any CNP Compliance Factor hereunder. Reasonable arrangements will be made to preserve the confidentiality of any competitively-sensitive or proprietary data that is accessed during any such inspection.

ADDITIONAL REQUIREMENTS APPLICABLE TO THE CNP PLANT FACTOR

By a comparable calculation a lessened retail revenue requirements and a per-kilowatt-hour reduction shall be computed based upon the book closing for the month in which an ownership interest in a previously certificated plant is transferred by the Company so as to remove a portion of said net plant from net plant dedicated to retail electric service. Such adjustment shall be based upon the amount of plant (net of any buy-back by the Company) transferred in excess of the amount of such net plant already allocated to the non-retail jurisdiction. Such adjustment shall be applied in each monthly billing beginning with the second calendar month following such transfer.

SPECIAL RULES

The Special Rules Governing the Operation of Rates RSE and CNP constitute an integral part of this rate.

RATE ECR
ENERGY COST RECOVERY RATE

By order of the Alabama Public Service Commission dated March 7, 2017 in Docket # 18148.

PAGE	EFFECTIVE DATE	REVISION
1 of 6	January, 2017 Billings	Third

AVAILABILITY

Same as the specific base rate schedule incorporating this Energy Cost Recovery Rate by reference.

APPLICABILITY

Applicable as an integral part of each base rate schedule of the Company in which reference is made to this Rate ECR.

EXPLANATORY STATEMENT

By its order in Docket #18148 (consolidating Docket #18152) issued May 29, 1981, the Alabama Public Service Commission abolished Rate FT, effective upon the replacement thereof by procedure to be defined in the rates, rules and regulations of the Commission incorporating, for application in Alabama, the Georgia fuel cost recovery system described in the order. That order also observed that it would be necessary in the transition to the new system "that the rate form be so arranged as not to constitute a revision or refiling of those general rate schedules of the Company now filed and under suspension and with respect to which the Commission must issue an order on or before October 18, 1981." To implement the Commission's May 29, 1981 order, Rate ECR (set forth below) will replace the Energy Cost Adjustment, Energy Cost Adjustment Calculation Procedure and the Special Rules Governing Administration of Rate FT, as last approved by the Commission. The tax provisions of Rate FT ("Income Tax Rate Adjustment," "General Tax Provisions," and "Adjustment for Local Taxes") continue to be effective and are designated as "Rate T."

GENERAL DESCRIPTION OF RATE

This Rate ECR is made a part of each of the base rate schedules of the Company to which Rate ECR is applicable and any modification to, amendment to or replacement of such base rate schedules. All bills rendered under such base rate schedules of the Company will be increased pursuant to the provisions of this Rate ECR and the effective Energy Cost Recovery factor calculated pursuant to this Rate ECR. This Rate ECR provides for the recovery by the Company of defined energy cost and establishes a procedure for the recovery of defined energy costs through the base rate schedules of the Company. After the development of the Energy Cost Recovery factor, it will be combined for billing purposes with the charges in the applicable rate schedule and shown as a single line item on the bill to the customer.

ENERGY COST RECOVERY FACTOR CALCULATION PROCEDURE (RATE ECR FORMULA)

The Energy Cost Recovery factor to be applied to each kilowatt-hour supplied by the Company under any base rate schedule of which this Rate ECR is made a part shall be calculated in accordance with the following formula:

$$\mathbf{ECRF} = \frac{\mathbf{ETEC}}{\mathbf{ETS}} \pm \mathbf{CF}$$

Where:

ECRF = Energy cost recovery factor to be applied to the retail kilowatt-hour sales during the current billing period and computed to the nearest one-thousandth of a cent per kilowatt-hour.

ETEC = The sum of:

(1) Estimated cost of fossil fuel and emission allowances to be issued out of Accounts 151 and 158.1 and charged to Accounts 501, 509, 518 and 547 of the Uniform System of Accounts prescribed by the Alabama Public Service Commission for the current billing period (three months) at the Company's generating plants, including also the Company's portion of estimated fossil fuel cost and emission allowances at generating plants whose capacity is shared with others and the Company's portion of such estimated costs at plants owned or operated by any affiliated company.

(2) Estimated cost of nuclear fuel to be recorded in Account 518 (exclusive of any fossil fuel expense therein to be issued from Account 151) of such Uniform System of Accounts for the current billing period (three months) at the Company's generating plants, including also the Company's portion of estimated nuclear fuel cost at generating plants whose capacity is shared with others and the Company's portion of such estimated cost at plants owned or operated by any affiliated company.

(3) Estimated purchased energy cost, exclusive of capacity or demand charges, shall be that portion of the estimated cost to be recorded in Account 555 of such Uniform System of Accounts for the current billing period (three months), excluding the cost related to the generation at plants owned or operated by any affiliated company already reflected in the estimated fossil and nuclear fuel costs above, when such energy is purchased on an economic dispatch basis or, otherwise, the estimated actual identifiable fossil fuel cost issued from Account 151 and nuclear fuel cost recorded in Account 518 or the estimated average cost of such fossil and nuclear fuel when such costs are not actually identifiable; less the estimated actual

identifiable cost of fossil and nuclear fuel (together with costs, gains, or losses associated with emission allowances) recovered through estimated inter-system sales or the estimated average cost of such fossil and nuclear fuel when such costs are not actually identifiable. Estimated purchased energy cost also includes any other cost or credit that is part of, or directly related to, a certificated power purchase arrangement if the Commission, in its order certifying the arrangement, so directs the inclusion of such cost or credit in Rate ECR.

(4) Gains, losses and costs associated with Company's utilization of futures, options and over the counter derivatives (including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps) for the purpose of hedging its energy and fuel costs.

(5) Gains, losses and costs recorded in Account 456 associated with sales of natural gas that are attributable to operating considerations at the Company's electric generating facilities.

ETS = Estimated total energy sales of the Company for the current billing period (three months), to be divided into the aforesaid sum (ETEC) so as to derive a factor (computed to the nearest one-thousandth of a cent per kilowatt-hour).

CF = The correction factor for prior periods represents the adjustment that is necessary to adjust prior estimates to actual data. This adjustment shall be computed as follows: Accumulate and total the actual monthly data in the categories of cost referred to in ETEC above. Deduct from this amount of total energy cost the following: (a) The energy cost recovery applicable to the wholesale customers, and (b) the energy cost recovery billed to the retail customers. The net amount represents the under- or over-recovery of energy cost applicable to retail customers for the month. The monthly amounts shall be accumulated through the end of the third month preceding the current billing period (three months). Then add the estimated under- or over-recovery of energy cost applicable to retail customers for the second (to be adjusted to Actual at the hearing if data available) and first months preceding the current billing period. This summation produces a dollar amount which, when divided by the estimated retail energy sales for the current billing period (three months), constitutes the correction factor (CF). The CF is computed to the nearest one-thousandth of a cent per kilowatt-hour.

In the development of the initial Energy Cost Recovery factor, the transition from the Energy Cost Adjustment contained in Rate FT to this Rate ECR must be recognized. Therefore, it will be necessary to estimate (later to be adjusted to actual) the under- or over-recovery for May and June 1981. This estimate shall be included as the correction factor in the initial Energy Cost Recovery factor. This estimate shall be computed as presently provided for in Rate FT.

RULES AND REGULATION GOVERNING APPLICATION OF ENERGY COST RECOVERY RATE

These rules and regulations are applicable to and are an integral part of Rate ECR. These rules and regulations established the procedures to be used in the determination of the Energy Cost Recovery factor.

1. On or before June 10, 1981, the Company shall submit to the Commission an estimate of energy cost and estimated sales for the three (3) calendar months beginning on July 1, 1981, and a proposed, initial Energy Cost Recovery factor computed in accordance with the calculation procedure contained in this Rate ECR, to be incorporated in base rate schedules of the Company as provided in this Rate ECR. On or before June 19, 1981, the Commission shall conduct a public hearing on the information so submitted for the purpose of determining its accuracy. The Company's testimony shall be under oath and shall, with any corrections thereto, constitute the Company's affirmative case. The Commission will issue an order on or before June 24, 1981, establishing the initial Energy Cost Recovery factor to be incorporated in the base rate schedules of the Company beginning July 1, 1981, and continuing until changed by the provisions of this Rate ECR.

2. After the initial Energy Cost Recovery factor is established, the Company can change such Energy Cost Recovery factor because of increased or decreased energy cost only after a submittal to the commission of an estimate of the Company's energy cost and sales for the three (3) consecutive calendar months beginning forty-five (45) days following the submittal and a proposed Energy Cost Recovery factor to recover those costs adjusted as required by the provisions of the Rate ECR Formula and subsection 4 of these rules and regulations. The Company shall submit its proposed Energy Cost Recovery factor and testimony forty-five (45) days in advance of the date the new Energy Cost Recovery factor is to be made effective as a part of the base rate schedules of the Company. Not less than twenty (20) days after any such submittal or after a Commission show cause order concerning the existing Energy Cost Recovery factor, the Commission shall conduct a public hearing on the information so submitted for the purpose of determining its accuracy. The Company's testimony shall be under oath and shall, with any corrections thereto, constitute the Company's affirmative case. At any such hearing, the burden of proof to show that an increased Energy Cost Recovery factor, based on fluctuations in energy cost, is just and reasonable shall be upon the Company.

   Formal intervention by customers of the Company shall be permitted. The staff of the Commission and formal intervenors shall have the right to examine all of the Company's records used in preparation of the testimony and exhibits of the Company, to cross-examine the Company's witnesses and present rebuttal testimony. If the staff of the Commission or any formal intervenors intend to submit rebuttal testimony recommending a different estimate of the Energy Cost Recovery factor, such testimony shall be reduced to writing and delivered to the Company five (5) days in advance of the scheduled hearing date. Following such hearing, the Commission shall issue an order stating the Energy Cost Recovery factor to be used by the Company during the next three (3) consecutive calendar months, or until changed as provided in this paragraph. The hearing shall be completed and submitted for issuance of an order within thirty-five (35) days from the Company's initial submittal. Should the Commission fail to issue such an order by the forty-fifth (45th) day after the Company's submittal, the Energy Cost Recovery factor proposed by the Company thereupon be deemed effective.

3. The Company shall compute, record and report to the Commission the monthly and accumulated over or under-recovery of actual energy cost resulting from application of the Energy Cost Recovery factor as soon as available.

4. It is the express purpose of this Rate ECR to allow the Company to recover the energy costs specifically identified in the Rate ECR Formula. Accordingly, the Rate ECR Formula contains an adjustment which requires the Company to collect or refund any accumulated under-recovery or over-recovery resulting from the difference between actual energy cost and revenues recovered pursuant to the estimated Energy Cost Recovery factor established by the Commission pursuant to this Rate ECR. At any time the Commission orders a change in the Energy Cost Recovery factor, recognition will be given to such accumulated over or under-recoveries so as to provide that the Company will neither recover more than nor less than its actual energy cost as defined in the ECR formula contained in this Rate ECR. Further, to provide for an orderly transition from the Energy Cost Adjustment contained in Rate FT to this Rate ECR, the under or over-recoveries under the Energy Cost Adjustment contained in Rate FT for the months of May and June, l981, will be incorporated and recognized in the accumulated over and under-recoveries provided for in the Rate ECR formula contained in this Rate ECR.

5. The Commission shall disallow and make appropriate adjustments for any reported energy cost that is the result of illegal or clearly imprudent conduct on the part of the Company.

6. All Commission orders establishing a changed Energy Cost Recovery factor pursuant to this Rate ECR shall contain the Commission's findings of fact and conclusions of law upon which the Commission's action is based. Such order shall be deemed a final order subject to judicial review under Alabama law.

7. The Commission shall not prohibit or limit the operation of this Rate ECR to the extent it permits rate increases or decreases to adjust for increased or decreased purchase power costs where such increased or decreased purchase power costs shall have become effective under the procedures of a Federal regulatory agency or under a contract approved by a Federal regulatory agency. Any subsequent refunds received by the Company with

respect to such increased purchase power costs which become effective under procedures of a Federal regulatory agency, or otherwise, shall be refunded by the Company to its customers in the manner directed by the Commission.

8. In submitting any estimate of energy costs under this Rate ECR, the Company shall disclose the name and address of each person, firm or corporation from whom the Company expects to purchase fuel, or the transportation of fuel, during the period covered by such estimate. Each such submittal shall also disclose, when applicable, any financial interests the Company has in any person, firm or corporation expected to supply fuel or transport fuel to the Company during the period covered by the estimate. It shall be the duty of the Commission to make public at each public hearing held pursuant to this Rate ECR any information disclosed by the Company pursuant to the requirements of this paragraph. It shall constitute a financial interest within the meaning of this paragraph:

   (a) For any member of the Board of Directors of the Company to be a member of the Board of Directors of a corporation supplying fuel, or transporting fuel, to the Company;

   (b) For any member of the Board of Directors of the Company to be the proprietor of, or a partner in, any business supplying fuel, or transporting fuel, to the Company; or

   (c) For any member of the Board of Directors of the Company or the Company to own ten percent (10%) or more of the stock of any corporation supplying fuel, or transporting fuel, to the Company.

9. The procedures provided for in Rate ECR and these Rules and Regulations are for the purpose of calculating, at a hearing, the energy costs of the Company, which are recoverable in full (but no more) as part of the application of Rate ECR and the rates to which it applies. Therefore, the submittals of the Company to initiate the calculation procedures and hearing are not "new schedules" subject to suspension within the meaning of Section 37-1-81, Code of Alabama 1975. The procedures and hearing are governed by the 45-day time limitation hereinabove specified.

RATE RSE
RATE STABILIZATION AND EQUALIZATION FACTOR

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

Effective for December 1982 billings and thereafter; modified effective for July 1985 billings and thereafter; modified effective for April 1990 billings and thereafter; modified effective for April 1998 billings and thereafter; modified effective May 1, 2002 for application to March 2003 billings and thereafter; modified effective October 16, 2005 for application to January 2007 billings and thereafter; modified effective September 20, 2013 for application to January 2014 billings and thereafter; modified effective June 1, 2018, for application to January 2019 billings and thereafter.

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AVAILABILITY

Same as the specific rate incorporating this Rate RSE by reference.

APPLICABILITY

Applicable as an integral part of each rate schedule of the Company in which reference is made to this Rate RSE.

EXPLANATORY STATEMENT

It is the purpose of Rate RSE to lessen the impact, frequency and size of retail rate increase requests by permitting the Company, through the operation of a filed and approved rate, to adjust its charges more readily to achieve the rate of return allowed it in the rate order of the Commission. By provisions in the rate, the charges are increased if projections for the upcoming year show that the designated rate of return range will not be met and are decreased if such projections show that the designated rate of return range will be exceeded. Other provisions limit the impact of any one adjustment (as well as the impact of any consecutive increases), and also test whether actual results exceeded the weighted equity return range.

APPLICATION OF RATE RSE AND CALCULATION PROCEDURES

Monthly billings on and after January 2019 shall be adjusted (increased or decreased) by the application of a rate stabilization and equalization factor ("RSE Factor") in accordance with the procedure herein described. By December 1, 2018, and by each December 1 thereafter, the Company's weighted return on projected average common equity, separated to retail electric service ("WRRCE"), shall be computed annually for the upcoming twelve-month period ending December 31 (such twelve-month period being the "rate year"). The WRRCE shall be computed on the basis of cost estimates and budgets prepared by the Company in the ordinary course of its business and in a manner consistent with the Uniform System of Accounts through the tabulations specified on Appendix B hereto. If the resulting WRRCE is less than 5.75% or more than 6.15% (5.75% - 6.15% being "the weighted equity return range"), then monthly bills under the respective rate schedules subject to this Rate RSE shall be increased or decreased by amounts per kilowatt-hour necessary, in total, to restore the WRRCE to 5.98% (the "adjusting point" in the weighted equity return range) plus a possible performance-based adder of 0.07%.

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

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The performance-based adder shall be added to the adjusting point if, at the time of the annual Rate RSE filing, the Company satisfies at least one of the following criteria: (i) an “A” credit rating equivalent with at least one of the recognized rating agencies, or (ii) a ranking in the top third of the most recent customer value benchmark survey or its successor in function. The above-described increases and decreases are accomplished through the application of an RSE Factor, which is developed by the formula contained in Appendix A hereto. Both Appendix A and Appendix B constitute an integral part of this Rate RSE. The RSE Factor shall be revised annually for application to billings beginning January of each rate year if the WRRCE computed with respect to that rate year is outside of the weighted equity return range. (For example, any revision of the RSE Factor for use beginning with January 2019 billings would be derived from the WRRCE computed for the upcoming twelve-month period ending December 31, 2019.)

For monthly billings commencing January 2019 and thereafter, the kilowatt-hour charges under the respective rate schedules shall be adjusted by applying the current annual revision (if any) of the RSE Factor to the existing kilowatt-hour charges, as theretofore adjusted for the cumulative effect of all prior RSE Factors and other adjustments (such as, for example, adjustments pursuant to Rate CNP).

ADJUSTMENT LIMITATIONS

Consecutive increases derived by the annual operation of Rate RSE shall be limited such that adjustments for any consecutive two-year period, when averaged together, do not exceed four percent (4%). Thus, the limitation governing any such consecutive increase shall be the percentage that, when combined with the percentage adjustment that was made applicable to monthly billings for the current year, produces an average of four percent (4%). Notwithstanding the foregoing, the maximum increase in any one year associated with the operation of Rate RSE shall not exceed five percent (5%) of the projected total retail revenues of the Company (“RR”) for the rate year used to compute the WRRCE. Hypothetical examples of the application of these limitations in the context of consecutive years include: 4.5% and 3.5%; 5.0% and 3.0%; 3.2% and 4.8%; 3.0% and 5.0%, and so forth.

PRIOR YEAR ACTUAL RESULTS

On or before March 1 of each year, the Company shall submit to the Commission a calculation of its actual weighted return on average retail common equity (“AWRRCE”) for the immediately preceding calendar year (“review year”) under this Rate RSE.

This AWRRCE will be calculated in the same manner as set forth under Appendix B, except that actual data will be substituted for the projected data used to develop the WRRCE for the same twelve-month period. If the AWRRCE derived through this calculation is above the weighted equity return range, then the Company shall determine the amount of revenue that caused the AWRRCE for the review year to exceed the top end of the designated range. The amount of revenue to be returned to customers shall be determined in the manner set forth in Appendix A ("refund factor") and, unless otherwise directed by the Commission, shall be refunded to retail customers by rate schedule. The implementation of any refunds to customers shall be accomplished through the application of credits on customer billings for the month of April following the review year.

OTHER LIMITATIONS AND PROVISIONS

Jurisdictional Allocations. In the computation of WRRCE and the RSE Factor, it is necessary for jurisdictional purposes that allocations be made as between electric and nonelectric operations and then as between retail electric service and electric service other than retail. For the applications of this Rate RSE, the Company will prepare and file by May 1 of each year, a cost-of-service study based upon data from the prior calendar year. The most recently filed cost-of-service study shall be used in the computation of WRRCE, RSE Factor, and the Refund Factor. Corrections or revisions proposed thereto, if not accepted by the Company, may be made the subject of a limited complaint proceeding under the Special Rules Governing Operation of this Rate. If such a complaint proceeding is instituted and not completed before the next annual RSE computation, the lower of the existing factors or the newly filed factors shall be used in computations under this Rate until such complaint proceeding is resolved.

RATE RSE
RATE STABILIZATION AND EQUALIZATION FACTOR

Alabama Power

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

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COMMISSION-REQUIRED ADJUSTMENTS

Advertising Expense. In its decision in Alabama Power Co. v. Alabama Public Service Commission, 359 So. 2d 776 (Ala. 1978), the Supreme Court of Alabama recognized advertising expense as an allowable expense for a utility company in a ratemaking proceeding. However, as an additional constraint upon expenditures by the Company, in each computation under Rate RSE one-half (1/2) of the amounts in Accounts 909 and 930.1 will be disallowed.

Lobbying Expense. The expenses of lobbying are appropriately charged to Account 426.4 and will not be charged to the ratepayer in any computation of this Rate RSE or otherwise.

Donations. In its decisions in Alabama Power Co. v. Alabama Public Service Commission, 359 So. 2d 776 (Ala. 1978) and Alabama Power Co. v. Alabama Public Service Commission, 390 So. 2d 1017 (Ala. 1980), the Supreme Court of Alabama has ruled that charitable donations (Account 426.1) cannot be proper expenses of a utility company for ratemaking purposes. Unless and until this matter is dealt with otherwise by legislation or subsequent court rulings, the Company will not undertake to move such expenditures from "below-the-line" to "above-the-line" status in any computation under this Rate RSE or in any ratemaking proceeding.

Civic Club Dues. Civic club dues are properly charged to Account 426.5 and will not be charged to the ratepayer in any computation of this Rate RSE or otherwise.

SPECIAL RULES

The Special Rules Governing Operation of Rates RSE and CNP constitute an integral part of this Rate.

RATE RSE – APPENDIX A
RATE STABILIZATION AND EQUALIZATION FACTOR

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DEVELOPMENT OF RSE FACTOR

The rate stabilization and equalization factor (RSE Factor) will be initially developed, and thereafter changed whenever the WRRCE for the rate year is not within the weighted equity return range. The RSE Factor shall be calculated for each respective affected rate schedule in accordance with the formula set out below and shall be applied in that schedule so as to adjust the kilowatt-hour charges as the same may have been adjusted by any previous applications of Rate RSE:

If $\dfrac{\dfrac{((AROR - WRRCE)/CEP)(RCE)}{1 - T}}{RR}$ is greater than L%, then $\dfrac{(L\% \times RR)\ \dfrac{BR_s}{BR_t}}{KWH_s}$ = RSE Factor*

If $\dfrac{\dfrac{((AROR - WRRCE)/CEP)(RCE)}{1 - T}}{RR}$ is equal to, or less than L%, then $\dfrac{\dfrac{((AROR-WRRCE)/CEP)(RCE)}{1 - T}\ \dfrac{BR_s}{BR_t}}{KWH_s}$ = RSE Factor*

*Rounded to nearest 0.0001 cent

Where, for the twelve-month period constituting the rate year,

AROR = Adjusting point of Weighted Equity Return Range, plus any earned performance-based adder.

WRRCE = Projected weighted return on average retail common equity.

CEP= Projected common equity percentage of capital structure.

RCE = Projected average retail common equity.

T = Combined Federal and State income taxes = $\dfrac{F + S - 2\,FS}{1 - FS}$

F being the effective statutory Federal income tax rate and S being the effective statutory State income tax rate.

RR = Projected total retail revenues from sale of electricity for the rate year.

L% = The applicable percentage limitation for the rate year.

BR_s = The projected base rate revenue from each respective retail rate schedule for the rate year. "Base rate revenue" from any schedule excludes amounts from Rate ECR and Rate T.

BR_t = The projected total base rate revenues from all retail rate schedules for the rate year. Such base rate revenues exclude amounts from Rate ECR and Rate T.

KWH_s = The projected kilowatt-hour sales by retail rate schedule for the rate year.

DEVELOPMENT OF REFUND FACTOR

The refund factor for the review year will be developed whenever the AWRRCE exceeds the top of the weighted equity return range (TROR). The refund factor shall be calculated for each affected rate schedule in accordance with the formula set forth below. The application of bill credits derived hereunder (or such other disposition as may be directed by the Commission) shall fully satisfy the Company's refund requirement under this Rate RSE.

If an upward adjustment under Rate RSE (or an upward adjustment in lieu of Rate RSE) did not occur in the review year, then calculate REF as follows:

If AET ≤ 0.005

$$REF = \frac{(((AET)(0.25))/ACEP)(ARCE)}{1-T}$$

If AET > 0.005 and ≤ 0.010

$$REF = \frac{((0.00125+((AET-0.005)(0.40)))/ACEP)(ARCE)}{1-T}$$

If AET > 0.010 and ≤ 0.015

$$REF = \frac{((0.00325+((AET-0.010)(0.75)))/ACEP)(ARCE)}{1-T}$$

RATE RSE – APPENDIX A
RATE STABILIZATION AND EQUALIZATION FACTOR

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If AET > 0.015

$$REF = \frac{((0.007+(AET-0.015))/ACEP)(ARCE)}{1-T}$$

If an upward adjustment under Rate RSE (or an upward adjustment in lieu of Rate RSE) occurred in the review year, then calculate REF as follows:

If AET ≤ 0.0075

$$REF = \frac{(((AET)(0.50))/ACEP)(ARCE)}{1-T}$$

If AET > 0.0075

$$REF = \frac{((0.00375+(AET-0.0075))/ACEP)(ARCE)}{1-T}$$

In all review years, calculate the AREF as follows:

If AWRRCE > (ACEP)(0.138), then

$$AREF = \frac{((AWRRCE-((ACEP)(0.138)))/ACEP)(ARCE)}{1-T}$$

Otherwise, AREF = 0

Develop the refund factor,

If REF ≥ AREF, then

$$\frac{(REF)\ \frac{BR_{sa}}{BR_{ta}}}{KWH_s} = \text{Refund Factor*}$$

Otherwise,

$$\frac{(AREF)\ \frac{BR_{sa}}{BR_{ta}}}{KWH_s} = \text{Refund Factor*}$$

*Rounded to nearest 0.0001 cent

RATE RSE – APPENDIX A
RATE STABILIZATION AND EQUALIZATION FACTOR

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Where, for the review year,

AWRRCE = Actual weighted return on average retail common equity.

TROR = Top of weighted equity return range.

AET = Amount exceeding top = AWRRCE - TROR

ACEP = Actual common equity percentage of capital structure.

ARCE = Actual average retail common equity.

REF = Amount to refund to customers.

AREF = Alternate amount to refund to customers.

T = Combined Federal and State income taxes = $\frac{F + S - 2\,FS}{1 - FS}$

F being the effective statutory Federal income tax rate and S being the effective statutory State income tax rate.

BR_{sa} = The billed base rate revenue recorded from each respective retail rate schedule for the review year. “Base rate revenue” from any schedule excludes amounts from Rate ECR and Rate T.

BR_{ta} = The total billed base rate revenues recorded from all retail rate schedules for the review year. Such base rate revenues exclude amounts from Rate ECR and Rate T.

KWH_s = The kilowatt-hour sales recorded for each respective retail rate schedule for the review year.

RATE RSE – APPENDIX B
RATE STABILIZATION AND EQUALIZATION FACTOR

Alabama Power

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

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DETERMINATION OF PROJECTED AVERAGE RETAIL COMMON EQUITY (RCE) AS OF DECEMBER 31, ___________:

		Column 1 **Total Amount** (Projected 12-mo. avg. bal.)		Column 2 **Non-Electric** (Projected 12-mo. avg. bal.)
Investment				
1. Electric Plant in Service (Account 101)	$	___________	(E)	$ ___________
2. Electric Plant Held for Future Use (Account 105)		___________		
3. Construction Work in Progress-Electric (Account 107)		___________		___________
4. Accumulated Provision for Depreciation and Amortization of Electric Utility Plant-Credit (Accounts 108 and 111)		___________	(E)	
5. Electric Plant Acquisition Adjustments-Net (Accounts 114 and 115)		___________		
6. Steam Heat Plant (Account 118)		___________		___________
7. Accumulated Provision for Depreciation of Steam Heat Plant-Credit (Account 119)		___________		___________
8. Nuclear Fuel-Net (Account 120)		___________		
9. Nonutility Property (Account 121)		___________		___________
10. Accumulated Provision for Depreciation and Amortization of Nonutility Property-Credit (Account 122)		___________		___________
11. Investment in Subsidiary Companies (Account 123)		___________		___________
12. Other Investments (Account 124)		___________		___________
13. Fuel Stock (Account 151)		___________		___________
14. Materials and Supplies (Account 154)		___________		___________
15. Merchandise (Account 155)		___________		___________
16. Allowance Inventory (Account 158)		___________		
17. Total	$	================		$ ================

RATE RSE – APPENDIX B
RATE STABILIZATION AND EQUALIZATION FACTOR

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

Effective for December 1982 billings and thereafter; modified effective for July 1985 billings and thereafter; modified effective for April 1990 billings and thereafter; modified effective for April 1998 billings and thereafter; modified effective May 1, 2002 for application to March 2003 billings and thereafter; modified effective October 16, 2005 for application to January 2007 billings and thereafter; modified effective September 20, 2013 for application to January 2014 billings and thereafter; modified effective June 1, 2018, for application to January 2019 billings and thereafter.

DETERMINATION OF PROJECTED AVERAGE RETAIL COMMON EQUITY (RCE) AS OF DECEMBER 31, ___________:

		Column 1 Total Amount (Projected 12-mo.avg. bal.)	Column 2 Non-Electric (Projected 12-mo. avg. bal.)
18.	Electric Investment Percent (Line 17, [Col. 1 - Col. 2 less UPS Investment of $_____] ÷ Col. 1)	__________ % (D)	
19.	Retail Electric Investment Factor	__________ %	
20.	Retail Investment Separation Factor (Line 18 x Line 19)	__________ %	

Common Equity Percentage of Capital Structure

21.	Common Equity (Accounts 201, 211 and 216)	$	__________
22.	Debt (Accounts 221-226 and 231)		__________
23.	Preferred Stock (Accounts 204-207 and 214)		__________
24.	Total (Line 21 + Line 22 + Line 23)	$	===============
25.	Common Equity Percentage of Capital Structure (CEP) (Line 21/Line 24)		=============== %

Retail Common Equity (RCE)

26.	Retail Common Equity (Line 20 x Line 21)	$	================

RATE RSE – APPENDIX B
RATE STABILIZATION AND EQUALIZATION FACTOR

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

Effective for December 1982 billings and thereafter; modified effective for July 1985 billings and thereafter; modified effective for April 1990 billings and thereafter; modified effective for April 1998 billings and thereafter; modified effective May 1, 2002 for application to March 2003 billings and thereafter; modified effective October 16, 2005 for application to January 2007 billings and thereafter; modified effective September 20, 2013 for application to January 2014 billings and thereafter; modified effective June 1, 2018, for application to January 2019 billings and thereafter.

PAGE	EFFECTIVE DATE	REVISION
Page 3 of 5	**June 1, 2018**	**Seventh**

DETERMINATION OF PROJECTED RETAIL NET INCOME FOR THE 12 MONTHS ENDING DECEMBER 31, _____________:

	Total Electric (Projected 12 mos. total)	Retail Electric (Projected 12 mos. total)	
Electric Operating Revenue:			
1. Sale of Electricity (Accounts 440-448)	$ ___________	$ ___________	(A)
2. Other Operating Revenues (Accounts 450-456)	___________	___________	(B)
3. Total Operating Revenues (Line 1 + Line 2)	___________	___________	
Electric Expenses:			
4. Electric Operation and Maintenance Expenses (Accounts 401 and 402)	___________		
5. Electric Depreciation and Amortization Expenses (Accounts 403-407)	___________		
6. Taxes Other than Income Taxes (Account 408.1)	___________		
7. Other Revenue Credits (Accounts 447-02xxx, 447-04xxx, 454 except 454-00904, and 456 except 456-00953)	___________ (A), (B)		
8. Electric Expenses Other than Income Taxes (Lines 4, 5, and 6 - Line 7)	___________		
9. Operating Income before Income Taxes (Line 3 - Line 8)	___________		
10. Income Taxes (Accounts 409-411)	___________		
11. Retail Expense Allocation Factor	___________ %		
12. Retail Expenses Other Than Income Taxes (Line 8 - UPS Expenses of $_____) x Line 11		___________	(D)
13. Retail Operating Income before Income Taxes (Line 3 - Line 12)		___________	
14. Retail Income Taxes (Line 13 ÷ Line 9) x Line 10		___________	
15. Net Retail Electric Operating Income (Line 13 - Line 14)		___________	

RATE RSE – APPENDIX B
RATE STABILIZATION AND EQUALIZATION FACTOR

Alabama Power

By orders of the Alabama Public Service Commission in Dockets #18117 and #18416.

Effective for December 1982 billings and thereafter; modified effective for July 1985 billings and thereafter; modified effective for April 1990 billings and thereafter; modified effective for April 1998 billings and thereafter; modified effective May 1, 2002 for application to March 2003 billings and thereafter; modified effective October 16, 2005 for application to January 2007 billings and thereafter; modified effective September 20, 2013 for application to January 2014 billings and thereafter; modified effective June 1, 2018, for application to January 2019 billings and thereafter.

DETERMINATION OF PROJECTED RETAIL NET INCOME FOR THE 12 MONTHS ENDING DECEMBER 31, ______________:

	Total Electric (Projected 12 mos. total)		**Retail Electric** (Projected 12 mos. total)	
Allowance for Funds Used During Construction				
16. Electric Allowance for Funds Used During Construction (AFUDC) - Gross	__________			
17. Retail Electric Allocation Factor	__________	%		
18. Retail Electric AFUDC (Line 16 - UPS Investment AFUDC of $_____) x Line 17			__________	(D)
Interest Income				
19. Interest Revenue (Accounts 419-00001, 419-00034, 419-00038 and 419-00066 through 419-00068) (net of tax)	__________			
20. Retail Interest Income (Line 19 x Retail Investment Separation Factor)	__________	%(C)	__________	
Interest Expense and Preferred Dividends:				
21. Interest Expense (Accounts 427-431)	__________			
22. Preferred Dividends (Account 437)	__________			
23. Total Interest Expense and Preferred Dividends [(Line 21 + Line 22) x Retail Investment Separation Factor]	__________	%(C)	__________	
Commission-Required Adjustments				
24. Commission-Required Adjustments (net of tax)	__________			
25. Retail Commission-Required Adjustments (Line 24 x Retail Expense Allocation Factor)	__________	%	__________	
Retail Net Income Available for Common Equity (RNI)				
26. Retail Net Income Available for Common Equity (Line 15 + Line 18 + Line 20 - Line 23 + Line 25)		$	================	

Weighted Return on Average Retail Common Equity

$\frac{\text{RNI}}{\text{RCE}} \times \text{CEP} = \text{WRRCE}$ __________ %

Notes:

Note (A): To conform with cost-of-service procedures, amounts included in Account 447 (Sales for Resale) associated with Non-Territorial Sales for Resale (subaccounts 447-02xxx and 447-04xxx) are excluded from Line 1 and included in Line 7.

Note (B): To conform with cost-of-service procedures, the total of Accounts 450 (Forfeited Discounts), 451 (Miscellaneous Service Revenues), 453 (Sales of Water and Water Power), subaccount 454-00904 (Rent from Leased Property on Customers' Premises-Other), and subaccount 456-00953 (Miscellaneous Electric Revenues-Return Check Charge) is included on Line 2. The remaining subaccounts for Accounts 454 (Rent from Electric Property) and 456 (Other Electric Revenues) are included in Line 7.

Note (C): Developed on Line 20 of retail common equity computation.

Note (D): To conform with cost-of-service procedures and to afford proper recognition of investment and associated allowance for funds and expenses associated with Unit Power Sales to Nonassociated Utilities, the investment and associated allowance for funds and expenses associated with such sales have been accounted for on Line 18 of RCE calculation and on Lines 12 and 18 of RNI calculation.

Note (E): For purposes of Rate RSE, the capitalization of asset retirement costs shall be excluded from Account 101 (Electric Plant in Service) and the associated depreciation shall be excluded from Account 108 (Accumulated Provision for Depreciation of Electric Utility Plant) pursuant to Accounting for Asset Retirement Obligations.

CONFIDENTIALITY AGREEMENT

THIS CONFIDENTIALITY AGREEMENT ("Agreement"), entered into and made effective as of the [__] day of [________________], is by and between Alabama Power Company ("Company") and Reviewing Representatives, as defined below, acting on behalf of [ ] (collectively "Intervenors").

W I T N E S S E T H:

WHEREAS, the Company has filed a petition for a certificate of convenience and necessity with the Alabama Public Service Commission in Docket No. [ ] (the "Petition"); and

WHEREAS, the non-public version of the Petition includes information that is proprietary and confidential to the Company—and for certain information to one or more third parties as well—the public disclosure of which could materially and adversely affect the effective and successful conduct of the Company's and/or the third parties' businesses, result in competitive disadvantage and business injury to them, and/or cause harm to other customers of the Company; and

WHEREAS, Intervenors have sought leave to intervene in Docket No. [ ] and have been, or are expected to be granted party status, with all rights and privileges as directed by the Commission in accordance with applicable law; and

WHEREAS, in connection therewith, Intervenors desire access to the non-public version of the Petition and other Confidential Information, as defined below; and

WHEREAS, to avoid any harmful outcomes, the Company desires to put in place this Agreement in order to safeguard against the intentional or inadvertent disclosure of any and all Confidential Information to third parties; and

WHEREAS, as evidenced by their execution of this Agreement, Intervenors are willing to accept and be legally bound by the terms and conditions set forth herein, as a precondition for the production of Confidential Information by Company to Intervenors.

NOW, THEREFORE, in consideration of the mutual promises and covenants made herein, and with the intent to be legally bound hereby, Company and Intervenors agree as follows:

1. As used in this Agreement, "Confidential Information" means: (i) the non-public version of the Petition, including all portions of the supporting testimony and exhibits marked Confidential; and (ii) all information provided or made available to Reviewing Representatives of Intervenors by the Company that the Company has designated, orally or in writing, as Confidential Information. Confidential Information also includes "Attorneys' Eyes Only" information, as designated by Company in accordance with Paragraph 5 below. The Company has the discretion to determine what Confidential Information it will make available under this Agreement, and the Intervenors and their Reviewing Representatives agree to accept the

Company's decision as to what information it makes available, as well as the Company's determination that such information is Confidential Information. However, the Company's determination shall in no way diminish or restrict Intervenors' discovery rights as permitted by the Alabama Public Service Commission.

2. Confidential Information shall not include information which:

(i) is or becomes generally available to the public other than as a result of acts by a Reviewing Representative, anyone to whom a Reviewing Representative supplies the Confidential Information, or anyone whose possession of the Confidential Information also is governed by a confidentiality agreement;

(ii) is disclosed to a Reviewing Representative by a third party which is not, to the knowledge of Reviewing Representative, prohibited from disclosing such information by a contractual, legal or other duty to Company; or

(iii) is provided to Intervenors by the Company and has not been designated "Confidential Information."

3. In the event the Company determines that Confidential Information has been disclosed without having been so marked, the Company reserves the right to designate the Confidential Information by providing contemporaneous notice to counsel for Intervenors and, as necessary, providing a copy of the Confidential Information marked accordingly. Thereafter, such Confidential Information shall be subject to the terms and conditions of this Agreement.

4. As used in this Agreement, "Reviewing Representative" means a person who has signed a copy of this Agreement (or the attached Appendix) for purposes of reviewing or receiving Confidential Information, who is:

(i) an Intervenor who has been granted party status in Docket No. [ ] or has an application for party status pending and to which the Company has not filed an objection; provided, however, that in the event Intervenors' application for party status is denied, then any Confidential Information provided prior to such action shall be handled in accordance with Paragraph 10;

(ii) an attorney representing said Intervenor(s);

(iii) attorneys, paralegals and other employees associated with an attorney described in item 2(ii) for purposes of Intervenors' participation in Docket No. [ ];

(iv) an expert or consultant (or an employee of such expert or consultant) retained by Intervenors for purposes of Intervenors' participation in Docket No. [ ]; or

(v) attorneys, paralegals and other employees of the Alabama Public Service Commission or the Office of the Attorney General of the State of Alabama.

Intervenors shall provide the Company with a list of all of its Reviewing Representatives and shall promptly update such list when new Reviewing Representatives are added.

5. Attorneys' Eyes Only: For Confidential Information that is proprietary and confidential to third parties, the Company reserves the right to designate such information Attorneys' Eyes Only and limit production of such information only to the following:

(i) an attorney representing an Intervenor who has been granted party status in Docket No. [ ];

(ii) attorneys, paralegals and other employees of the Alabama Public Service Commission or the Office of the Attorney General of the State of Alabama.

6. The Reviewing Representatives agree to protect and maintain the confidentiality of all Confidential Information and shall not, directly or indirectly, in whole or in part, or in any derivative form:

(i) use such Confidential Information for any purpose other than in connection with Intevenors' direct participation in Docket No. [ ]; provided, however, that the use of Confidential Information in connection with the above shall include appropriate protections to maintain the confidential nature of the information including, without limitation, the employment of redactions, sealed pleadings, and other such measures; or

(ii) disclose such Confidential Information to any person who is not a signatory to this Agreement, without regard to whether such person is an officer, employee or staff member of Intervenors; holds a membership interest in or affiliation with Intervenors; or is officer, employee or staff member of an affiliate or subsidiary of Intervenors.

7. In the event a Reviewing Representative becomes aware of an actual or potential breach of this Agreement including, without limitation, the actual or potential disclosure or review of Confidential Information by any person who has not executed this Agreement, or any actual or potential unauthorized use of Confidential Information, Intervenors or the Reviewing Representative shall, to the extent practicable, take steps to prevent such actual or potential breach and shall also promptly give written notice to the Company of such facts.

8. Intervenors and each of their Reviewing Representatives expressly understand and agree that in the event of any breach or threatened breach of this Agreement, the Company could be irreparably and immediately harmed and may not be made whole by monetary damages and may be entitled to, in addition to any other remedy to which it may be entitled at law or in equity, seek injunctive relief. In the event of a breach of this Agreement, the Company shall be entitled to all remedies available at law or in equity, including all costs and expenses (including reasonable attorneys' fees) incurred by the Company in connection with efforts to enforce the terms and conditions of this Agreement.

9. Company and Reviewing Representatives agree that this Agreement shall be construed in accordance with the laws of the State of Alabama, without reference to its conflict of

laws principles. Company and Reviewing Representatives further agree to submit to the jurisdiction of the state and federal courts situated in Jefferson County, Alabama to adjudicate any dispute arising out of relating to this Agreement including, but not limited to, the enforcement of rights under Paragraph 8. BOTH COMPANY AND REVIEWING REPRESENTATIVES WAIVE, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT TO A TRIAL BY JURY IN RESPECT OF ANY PROCEEDINGS ARISING OUT OF RELATING TO THIS AGREEMENT. Any judgment awarded may be enforced by any court having competent jurisdiction thereof.

10. Intervenors and each of their Reviewing Representatives expressly understand and agree that by gaining access to Confidential Information in accordance with this Agreement, all such Reviewing Representatives shall be deemed ineligible, for a period of three (3) years from the date of such access, from:

(i) any involvement in the development of proposals to, or the negotiation and preparation of any contracts or other arrangements with, the Company or any of its affiliates within the Southern Company system related to the supply of capacity, energy, and/or renewable attributes associated with any generating facility; or

(ii) any participation in a Request for Proposal ("RFP"), or any consultation with or representation of a participant in an RFP, that is extended by the Company or any of its affiliates within the Southern Company system and that solicits proposals for such supply of capacity, energy, and/or renewable attributes associated with any generating facility.

11. All Confidential Information in the possession of Reviewing Representatives at this conclusion of proceedings related to Docket No. [ ] shall be returned or destroyed at the election of the Company, including all originals, copies, translations, notes, or any other form of said material, as well as any and all written, printed, or other material or other information derived from the Confidential Information. To the extent a Reviewing Representative is instructed to destroy the Confidential Information, the Reviewing Representative shall promptly provide written or electronic confirmation to the Company that the requirements of this paragraph have been satisfied.

12. The obligations and commitments established by this Agreement, except where otherwise provided, shall remain in full force and effect for five (5) years following the effective date.

13. This Agreement may be executed in counterparts, each of which is deemed an original, but all of which together constitute one and the same instrument. Facsimile/electronic signatures hereto are deemed original signatures.

[SIGNATURE BLOCKS ON SUBSEQUENT PAGE]

IN WITNESS WHEREOF, the parties hereto have entered into this Agreement as of the day and year first herein above written.

[Intervenor]

Printed Name: ______________________

Signature: ______________________

Date: ______________________________

Alabama Power Company

Printed Name: _______________________

Signature:___________________________

Title: ______________________________

Date: _______________________________

APPENDIX

List of additional Intervenors' Reviewing Representative signatories to the foregoing Confidentiality Agreement pertaining to Confidential Information provided or made available in connection with this Agreement. Signatories below each certify that they have read the forgoing Confidentiality Agreement, understand the obligations and commitments therein, and agree to be personally bound thereby.

By: ______________________________	By: ______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________
Date: _______________________________	Date: _______________________________
By: ______________________________	By: ______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________
Date: _______________________________	Date: _______________________________
By: ______________________________	By: ______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________
Date: _______________________________	Date: _______________________________
By: ______________________________	By: ______________________________
Name: ______________________________	Name: ______________________________
Title: ______________________________	Title: ______________________________
Date: _______________________________	Date: _______________________________

NOTICE OF PETITION

ALABAMA POWER COMPANY

Petitioner

PETITION: FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY FOR: (I) THE CONSTRUCTION AND INSTALLATION OF COMBINED CYCLE GENERATING CAPACITY AT THE SITE OF PETITIONER'S BARRY STEAM PLANT LOCATED IN MOBILE COUNTY, ALABAMA; (II) THE ACQUISITION OF EXISTING COMBINED CYCLE GENERATING CAPACITY IN AUTAUGA COUNTY, ALABAMA; (III) THE ACQUISITION OF RIGHTS AND THE ASSUMPTION OF PAYMENT OBLIGATIONS UNDER A PURCHASED POWER AGREEMENT FOR THE OUTPUT OF COMBINED CYCLE GENERATING CAPACITY OPERATED IN MOBILE COUNTY, ALABAMA; AND (IV) THE ACQUISITION OF RIGHTS AND THE ASSUMPTION OF PAYMENT OBLIGATIONS UNDER PURCHASED POWER AGREEMENTS FOR THE OUTPUT FROM FIVE SOLAR PHOTOVOLTAIC AND BATTERY ENERGY STORAGE SYSTEMS, LOCATED IN CALHOUN, CHAMBERS, DALLAS, HOUSTON AND TALLADEGA COUNTIES; TOGETHER WITH ALL TRANSMISSION ARRANGEMENTS, STRUCTURES, SUBSTATIONS, AND FACILITIES, ENVIRONMENTAL CONTROL MEASURES, FACILITIES OR ARRANGEMENTS FOR THE HANDLING, TREATMENT, TRANSPORTATION, DELIVERY AND PROCESSING OF FUEL, AND ANY AND ALL OTHER APPLIANCES, APPURTENANCES, FACILITIES, RIGHTS, EQUIPMENT, ACQUISITIONS, COMMITMENTS AND ACCOUNTING AUTHORIZATIONS NECESSARY FOR OR INCIDENT THERETO.

DOCKET NO. _________

Interested parties are hereby advised that the above-captioned Petition by Alabama Power Company was filed with and received by the Commission on September 6, 2019.

All petitions for leave to intervene in this matter must be filed by 5:00 PM (CDT) on September __, 2019. Petitions shall set forth the basis for the proposed intervention, including the position and interest of the petitioner in the proceeding.

The above-described deadline and requirements governing interventions by any interested parties will be strictly adhered to for purposes of this proceeding. A subsequent procedural order pertaining to the hearing on the Company's Petition, as well as any attendant matters, will be issued soon thereafter.

BY THE COMMISSION: **Walter L. Thomas, Jr.**
Secretary