2022 INTEGRATED RESOURCE PLAN

SUMMARY REPORT

Alabama Power

2022

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EXECUTIVE SUMMARY

The 2022 Integrated Resource Plan Summary Report ("2022 IRP") provides an overview of the results of the most recently completed integrated resource planning process (the "IRP process") for Alabama Power Company ("Alabama Power" or "Company"). Integrated resource planning is a comprehensive, data-intensive process that establishes the foundation for certain decisions affecting the Company's future portfolio of supply-side and demand-side resources. The IRP process itself does not determine what specific resources the Company must procure in the future. Rather, this management tool facilitates the Company's ability to make resource decisions through (i) its development of an indicative list of future additions that meet appropriate reliability requirements in a cost-effective manner, and (ii) its accounting for risks and uncertainties inherent in planning for resources sufficient to meet forecasted customer demand. The IRP process supports the Company's management of its existing portfolio of supply-side and demand-side resource options, better enabling the Company to adapt and respond to changes in external factors that could influence the Company's ability to provide reliable electric service to its customers.[1]

The IRP Summary Report is developed every three years and reviewed with the Alabama Public Service Commission ("APSC"). Through this review, the APSC remains apprised of the projected timing of resource additions, consistent with the Company's duty of service to customers and the need to provide the desired level of service reliability in a cost-effective manner. More recently, the APSC also has received information regarding the IRP process through proceedings held in Docket No. 32953 and Docket No. 33182 concerning petitions by Alabama Power for certificates of convenience and necessity related to specific resource additions.

Alabama Power remains committed to maintaining a diverse supply-side generating portfolio, along with cost-effective demand-side resources that benefit all customers. Resource diversity on the supply side—which includes nuclear, natural gas, coal, oil, hydroelectric, wind and solar 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 continues to transition in response to various factors, particularly the cost of compliance with environmental regulations issued by the U.S. Environmental Protection Agency ("EPA"). In 2021, Alabama Power submitted its plans for compliance with EPA's effluent limitations guidelines ("ELG") rule to the Alabama Department of Environmental Management. These plans, as set forth in two Notices of Planned Participation ("NOPP"), reflect Alabama Power's intent to cease coal combustion at Plants Barry and Gaston by not later than December 31, 2028. Additionally, efforts to address carbon dioxide ("CO2") and greenhouse gas ("GHG") emissions continue to impact the long-term planning of the Company's generating fleet. The cost and operating implications for the Company's supply-side resources related to these and other considerations remain factors in the planning scenarios utilized in the 2022 IRP.

[1]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 resources, including demand-side management programs.

The Company's capacity planning decisions were once driven by summer peak loads alone, and Alabama Power relied on a corresponding summer-focused Target Reserve Margin ("TRM") to address reliability concerns in that season. Since the 2019 IRP planning process, Alabama Power has utilized dual-season TRMs to address reliability concerns in both the winter and summer seasons. This transition stemmed from operational experiences and the growing awareness that winter peak demand for the Alabama Power system presented reliability risk. Seasonal planning provides greater visibility into capacity needs in both the summer and the winter periods, rather than limiting reliability decisions to a single season.

Alabama Power's 2022 IRP reflects the results of the most recent Reserve Margin Study ("RMS") for the Southern Company System ("System"). The RMS provides a detailed reliability analysis that yields TRMs for the System. For long-term planning starting in 2025 and beyond, the study supports a summer season TRM of 16.25 percent and a winter season TRM of 26.00 percent. Consistent with past practice, the RMS also evaluated reliability needs on a shorter-term basis (2022-2024), and for planning purposes calls for a 15.75 percent target and a 25.50 percent target for the summer and winter seasons respectively. 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 margins for the System. Thus, the diversified summer TRMs for Alabama Power are 15.28 percent over the long-term and 14.78 percent over the short-term. Likewise, Alabama Power's diversified winter TRMs are 25.18 percent over the long-term and 24.69 percent over the short-term. These diversified values are subject to change in response to changes in System load. Figure ES-1 compares the previous planning TRMs to those predicated on the new RMS.

FIGURE ES-1: Summer and Winter TRM Comparison

	2019 IRP	2022 IRP
System Long-Term Planning TRM (Summer)	16.25%	16.25%
System Short-Term Planning TRM (Summer)	15.75%	15.75%
Diversified Long-Term Planning TRM (Summer)	14.89%	15.28%
Diversified Short-Term Planning TRM (Summer)	14.39%	14.78%
System Long-Term Planning TRM (Winter)	26.00%	26.00%
System Short-Term Planning TRM (Winter)	25.50%	25.50%
Diversified Long-Term Planning TRM (Winter)	25.25%	25.18%
Diversified Short-Term Planning TRM (Winter)	24.75%	24.69%

Based on these TRMs, and taking into account the addition of resources approved by the APSC in Docket No. 32953 and Docket No. 33182, Alabama Power projects sufficient long-term reserves to meet its obligations until the late 2020s. Barring any additional changes, the Company anticipates having to address this forecasted capacity need, and will be assessing its options for most effectively meeting that need in a timely manner.

I. INTRODUCTION AND OVERVIEW

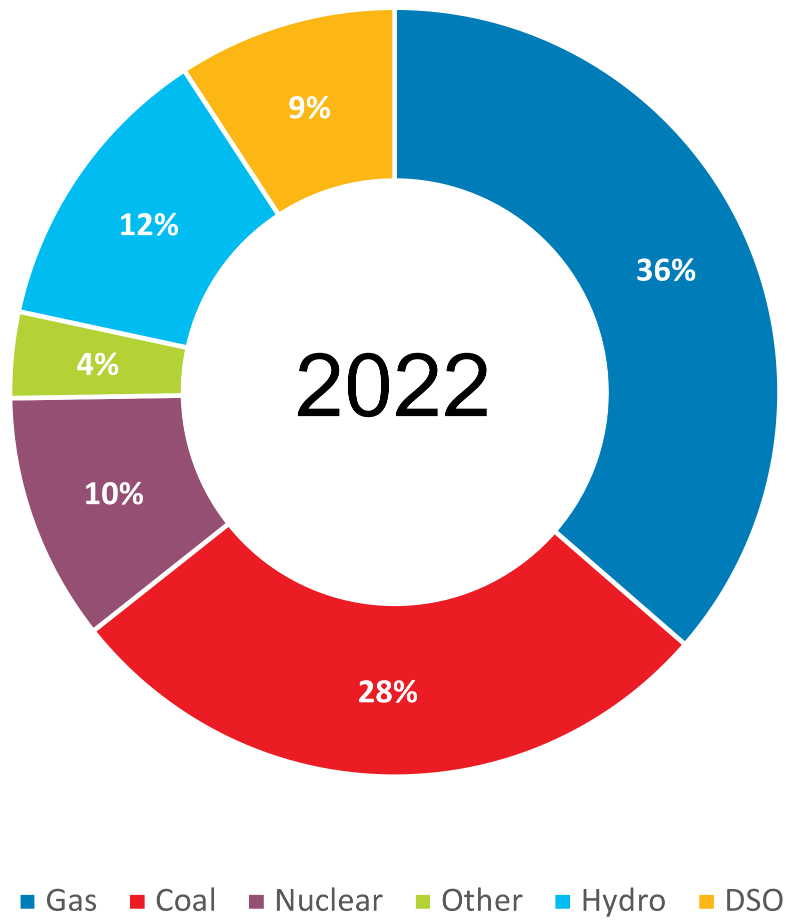
Alabama Power is an investor-owned electric utility, organized and existing under the laws of the State of Alabama, and is a subsidiary of the Southern Company. In addition to Alabama Power, the Southern Company is the parent of Georgia Power Company, Mississippi Power Company, and Southern Power Company (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 1.5 million customers, of which approximately 86 percent are residential, 13.5 percent are commercial, and 0.5 percent are industrial and other. Alabama Power has approximately 1.58 million transmission and distribution poles, and approximately 86,000 miles of wire. The Company strives to maintain cost-effective and reliable service to its customers. For the years 2020-2021, the Company had a service reliability of over 99.9 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[2], combined heat and power, and demand-side management ("DSM") programs.

As of January 2022, Alabama Power had a planning resource capability of approximately 16,300 MW for the winter planning period and 15,800 MW for the summer planning period. The resources reflect a diverse mix of capacity, as reflected in the following charts.

[2] As applicable to all references of renewable projects in this 2022 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 2022 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. The IRP yields an indicative schedule of 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 Company System Intercompany Interchange Contract ("IIC"), which provides for coordinated System operations and centralized unit commitment and joint dispatch of the Operating Companies' respective generating units (the "Southern Pool"). In order to take advantage of economies of scale, the retail Operating Companies (i.e., Alabama Power, Georgia Power and Mississippi Power) 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. Under the IIC, an operating company can benefit from temporary surpluses of energy that might be present in the Southern Pool. Each operating company is expected, however, to have adequate resources, including an appropriate level of reserves, to reliably serve its own load obligations, and cannot rely on the capacity of affiliates to meet the long-term needs of its customers.

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 systems in the Southeastern United States. Likewise, Alabama Power and the other retail Operating Companies, along with nine other transmission owners, 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 long-term 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 now operates on a dual-season peaking basis. That is, the traditional summer peaking characteristics of the System have given way to significant demands in the winter months. In recent years, Alabama Power's winter peak demand, both actual and weather-normalized, has exceeded the summer peak demand, and the Company's most recent load forecast projects a predominant winter peak demand. The Company's load forecast is discussed further in the Section IV.B.

II. COORDINATED PLANNING AND OPERATIONS WITH POWERSOUTH

In 2021, Alabama Power and PowerSouth Energy Cooperative entered into the Coordinated Planning and Operations Agreement. Under the agreement, which carries a minimum 10-year term, the two systems have combined their operations, with their respective generating resources now jointly committed and dispatched. The agreement is expected to create energy cost savings and enhanced system reliability for Alabama Power and PowerSouth; however, both companies remain obligated to plan for their respective systems and coordinate those plans for the mutual benefit of their customers. In addition, PowerSouth must carry reserves commensurate with Alabama Power's diversified reserve margins.

III. ENVIRONMENTAL STATUTES AND REGULATIONS[3]

III.A. GENERAL

The Company's operations are subject to extensive regulation by federal, state and local 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; analogous state statutes; and related federal and state regulations. Compliance with these and other environmental requirements involves significant capital and operating costs. At December 31, 2021, the Company had approximately $5.68 billion invested 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 $195 million from 2022 through 2026. These estimates do not include any estimated compliance costs associated with the regulation of CO2 emissions from existing fossil fuel-fired electric generating units. Costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Coal Combustion Residuals ("CCR") Rule 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 environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital, operations expenditures, and costs reflected in ARO liabilities is affected by the final requirements of new or revised environmental regulations and the outcome of any associated legal challenges; the cost and performance of control technologies and options; the cost and availability of emissions allowances; and the Company's projected capacity and energy needs and 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, among other sources, additional unit retirements, installation of new environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units.

Compliance with any new federal or state legislation or regulations relating to air, water and land resources or other environmental programs 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

[3] 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, 2021, 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.

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.

III.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 Congress, the EPA, or by the Alabama Department of Environmental Management. Certain notable programs are discussed below.

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 2012 MATS Rule was April 16, 2015, with provisions for extensions to April 16, 2016. The compliance strategy for the rule included emission controls, retirements and fuel conversions.

On June 29, 2015, the Supreme Court ruled that the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant ("HAP") emissions from EGUs. The EPA issued a Supplemental Finding in response to the Supreme Court's decision on April 15, 2016. The Supplemental Finding revised the EPA's consideration of costs, but it did not have any impact on the 2012 MATS Rule compliance requirements or deadlines.

On April 16, 2020, the EPA published a reconsideration of its assessment of costs in the 2016 MATS Supplemental Finding and concluded there were flaws in the Supplemental Finding's approach to considering costs and benefits. In the 2020 MATS Supplemental Finding reconsideration rule, the EPA determined that a proper consideration of costs demonstrates that the total projected cost of compliance with MATS dwarfs the monetized HAP benefits of the rule. However, the EPA concluded that the absence of such a finding does not affect the status of the 2012 MATS Rule, which remains in effect. The EPA also took final action on the required Residual Risk and Technology Review and determined that the residual risks from HAP emissions from these EGUs are acceptable and there have been no new cost-effective HAP controls identified to achieve further emission reductions. Therefore, the EPA determined that revisions to the 2012 MATS Rule are not warranted.

On January 31, 2022, the EPA announced it had again reviewed the question of costs associated with the MATS Rule and proposed to revoke the 2020 reconsideration rule and reinstate the 2016 Supplemental Finding affirming that it is "appropriate and necessary" to regulate EGUs. The EPA also announced that it would consider whether to rescind the Risk and Technology Review from the 2020 reconsideration rule and potentially impose more stringent requirements on EGUs in a separate action. Litigation concerning the Supplemental Finding is presently in abeyance pending resolution of subsequent MATS regulatory activity, and litigation over the EPA's additional actions is expected. Currently, this regulatory development does not change the compliance strategy and the Company continues to comply with the 2012 MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard ("NAAQS"). As part of its five-year NAAQS review cycle of the ozone standards, the EPA decided in a final rulemaking on December 23, 2020, to retain without revision the 2015 ozone NAAQS (with which all areas within the Alabama Power service territory are in attainment). However, in a court filing on October 29, 2021, the EPA confirmed that it will reconsider the December 2020 ozone NAAQS rule, stating that it intends to complete the review by the end of 2023. This review could result in a further tightening of the ozone standard.

The EPA regulates fine particulate matter ("PM") concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the current PM NAAQS. On December 18, 2020 as part of the required review cycle of the PM NAAQS, the EPA determined to retain all existing NAAQS for particulate matter. However, on June 10, 2021, the EPA announced its decision to reconsider the standards and stated that the scientific evidence supports lowering the annual standard from the current level. A final rulemaking could be issued as early as spring of 2023.

The EPA also has prescribed NAAQS for sulfur dioxide ("SO_2"). Final revisions to the 1-hour SO_2 NAAQS became effective in 2010. In January 2017, the Company submitted modeling showing attainment of the SO_2 standard in the vicinity of its coal-fired generating plants. On December 21, 2020, the EPA finalized Round 4 designations for the SO_2 NAAQS, which included the designation of a portion of Shelby County as "attainment/unclassifiable." This EPA action concluded designations for Alabama regarding the 2010 1-hour SO_2 NAAQS, with no area in the state being designated as nonattainment.

In 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") to address impacts in downwind states of SO_2 and NOx emissions from fossil fuel-fired electric generating plants. CSAPR established emissions trading programs and budgets for certain states and allocates emissions allowances for sources in affected states, including Alabama. In 2016, the EPA published a final rule, the CSAPR Update Rule, establishing more stringent ozone season NOx emissions budgets for several states, including Alabama, in order to ensure compliance with the 2008 ozone NAAQS.

The CSAPR Update Rule, however, did not address the more stringent 2015 ozone NAAQS, and on February 22, 2022, the EPA proposed to disapprove provisions of the Alabama State Implementation Plan ("SIP") containing interstate transport obligations addressing the 2015 ozone NAAQS. Subsequently, ADEM withdrew its transport SIP provisions and proposed a replacement, but in a related action, the EPA released a proposed Federal Implementation Plan ("FIP") on March 11, 2022 to require ozone season NOx reductions from 26 states including Alabama, in order to satisfy these states' interstate transport obligations with respect to the 2015 ozone standard. On August 17, 2022, ADEM and the state of Alabama jointly filed a petition for review of EPA's Finding of Failure to Submit an Interstate Transport SIP for the 2015 ozone standard in the Eleventh Circuit Court of Appeals. The impact on Company operations and compliance costs from the implementation of a new ozone transport SIP or FIP cannot be determined at this time.

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 scenic areas (Class I areas including national parks and wilderness areas) across the United States by 2064. Regional haze regulations established specified planning periods where states must meet reasonable progress toward visibility milestones at each Class I area. These planning period reviews could require further reductions in certain pollutants, such as particulate matter, SO_2 and NOx, which may result in increased compliance costs to the Company. Alabama is currently in the process of developing SIP revisions for the second regional haze planning period. SIP revisions must evaluate if further controls for visibility impairing pollutants during the 2021-2028 period are necessary or could be applied to stationary sources. The impact on Company operations and compliance costs from the ongoing implementation of regional haze regulations is unknown at this time.

On February 28, 2022, the EPA finalized amendments to the National Emission Standards for Hazardous Air Pollutants for stationary combustion turbines. The final action removes the stay of the standards for new premix and diffusion flame gas-fired turbines that was promulgated in 2004, affecting turbines at major sources of HAPs that began construction after January 14, 2003. Affected units must meet formaldehyde limits and continuously monitor and maintain minimum flue gas temperatures. Further, there are restrictions for startup, shutdown and malfunctions for affected turbines. At this time, the rules have had limited impact on Company operations, with no existing units being affected. Only the combustion turbines at the under-construction Plant Barry Unit 8 would be subject to these requirements.

On June 12, 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 22, 2016. On January 11, 2022, the EPA issued a rule finding that 12 states, including Alabama, have failed to submit SIP revisions addressing the 2015 SSM Rule. Litigation over the EPA's 2015 rule, which was stayed while the EPA conducted additional review, is now before the D.C. Circuit Court of Appeals for a decision as to the scope of the EPA's authority to require states to revise their SSM policies. A decision could be issued as early as fall of 2022. The impact on Company operations and compliance costs from the implementation of future SSM requirements is unknown at this time.

III.C. WATER QUALITY

Compliance with the Clean Water Act ("CWA") and associated regulations has also been and will continue to be a significant focus for the Company. While there are various regulatory activities arising in the context of the CWA, such as cooling water intake requirements under section 316(b) and the recent litigation around the definition of Waters of the United States, effluent limitation guidelines ("ELG") have been a significant compliance area for Alabama Power in recent years. Established by the EPA nearly 50 years ago, ELG regulates discharge of wastewater from steam electric generating facilities. On November 3, 2015, the EPA published its first major revision to the steam electric ELG in over 30 years. The new ELG rule ("2015 ELG Rule") imposed more stringent technology-based requirements on wastewater discharges from coal-fired plants, including fly ash transport water ("FATW"), bottom ash transport water ("BATW"), and flue gas desulfurization ("FGD" or "scrubber") wastewater. The new effluent limits have been implemented in National Pollutant Discharge Elimination System ("NPDES") permits issued by ADEM, with the precise date of application to a facility determined by information provided to ADEM by the Company.

In September 2017, the EPA released a final rule postponing by two years the 2015 ELG Rule's earliest possible compliance date for the FGD wastewater and BATW streams while the agency reconsidered the 2015 rulemaking. The EPA subsequently published its final ELG Reconsideration Rule ("2020 ELG Rule") in the Federal Register on October 13, 2020, with an effective date of December 14, 2020.

The 2020 ELG Rule differed from the 2015 ELG Rule in several important respects. First, it established changes to certain discharge limitations applicable to FGD wastewater and BATW, including more stringent limitations for certain constituents. In addition, it altered certain mandatory compliance timelines, including extending the latest "as soon as possible" date from December 31, 2023 to December 31, 2025. Further, the 2020 ELG Rule provided alternate compliance options, in lieu of complying with the generally applicable limitations, and also established a process allowing regulated entities to transfer among the various compliance options, subject to specified requirements. Any facility wanting to comply with the permit conditions and discharge limitations associated with any of the alternate compliance options included in the 2020 ELG Rule was required to submit a Notice of Planned Participation or "NOPP" to its permitting authority by October 13, 2021.

On July 26, 2021, the EPA announced its intent to further revise its 2015 and 2020 ELG Rules. The proposed rule is expected to be published in the fall of 2022. In the interim, the EPA made clear that the 2015 and 2020 ELG Rules remain in effect and that the agency expects permitting authorities to continue to implement the current regulations in NPDES permits. Legacy wastewater and combustion residual leachate discharges also are expected to be addressed in this forthcoming rulemaking.

Alabama Power intends to comply with the 2020 ELG Rule in various ways. For Plant Miller, Alabama Power has deployed compliance solutions to manage effluent limitations consistent with the applicable requirements. For Plant Barry Units 4 and 5, Alabama Power intends to permanently cease coal combustion by repowering Unit 4 to operate solely on natural gas and retiring Unit 5 not later than December 31, 2028. In this IRP, the assumed retirement date for Barry Unit 5 is January 1, 2024; however, that assumption is subject to change based on prevailing operating conditions. For Plant Gaston Units 1-5, the permanent cessation of coal combustion likewise is planned, with Units 1-4 expected to retire and Unit 5 repowered to operate solely on natural gas by the end of 2028. To the extent Alabama Power is reasonably able (consistent with proper planning and electric system reliability) to implement these decisions in a more expedient manner, it will undertake to do so.

III.D. COAL COMBUSTION RESIDUALS

In 2015, the EPA finalized the CCR Rule, which established non-hazardous solid waste regulations for the management and 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 facilities to be evaluated against a set of performance criteria. ADEM has also finalized regulations regarding the handling of CCR. In April 2019, Alabama Power initiated closure of its unlined CCR impoundments and ash ponds. At this time, Alabama Power does not expect the closure process to impact the availability or operation of its active supply-side resources.

III.E. GLOBAL CLIMATE ISSUES

The EPA has twice attempted to promulgate rules aimed at regulating CO2 emissions from existing fossil fuel-fired electric generating units. First, in October 2015, the EPA finalized the Clean Power Plan ("CPP"). The CPP would have established a cap-and-trade program that relied on shifting fossil generation to renewables, but it was stayed by the United States Supreme Court, on June 19, 2019, and did not go into effect. The EPA then repealed the CPP and replaced it with the Affordable Clean Energy rule ("ACE"). The EPA determined that the CPP had exceeded the EPA's statutory authority under the CAA by relying on standards and methods that could not be implemented by individual facilities. The ACE rule was appealed, and on January 19, 2021, the D.C. Circuit vacated the ACE rule and remanded it to the EPA. Petitions were filed with the United States Supreme Court to review the D.C. Circuit's decision, and a decision from the Supreme Court was issued on June 30, 2022. In its decision, the Court held that Section 111 of the CAA did not allow EPA to set emission limits for existing coal-fired power plants based on generation shifting, as it did in the CPP. The EPA has stated that it expects to propose a replacement rule in 2023. The ultimate impact on operations and compliance costs of potential regulations limiting carbon emissions from Company facilities is unknown at this time.

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 2015 NSPS rule set standards of performance for new, modified and reconstructed EGUs, which includes stationary combustion turbines and fossil-fired steam boilers. This proposal would reduce the stringency of the 2015 NSPS rule by not basing the new and reconstructed fossil-fired steam boiler and IGCC standards on partial carbon capture and sequestration. The EPA has not taken final action to revise the 2015 NSPS rule. The impact of any changes will depend on the content of the final rule and the outcome of any legal challenges.

Over the years, Congress has considered many legislative proposals that would reduce emissions of GHGs and/or mandate generation of electricity from renewable energy sources. Legislation can take many forms, such as an emissions cap, a carbon tax, renewable energy standards, and clean energy standards. The Inflation Reduction Act represents the first federal legislation with provisions intentionally designed to reduce GHG emissions, but the scope and impact of that legislation remains under evaluation.

IV. INTEGRATED RESOURCE PLAN

IV.A. PROCESS OVERVIEW

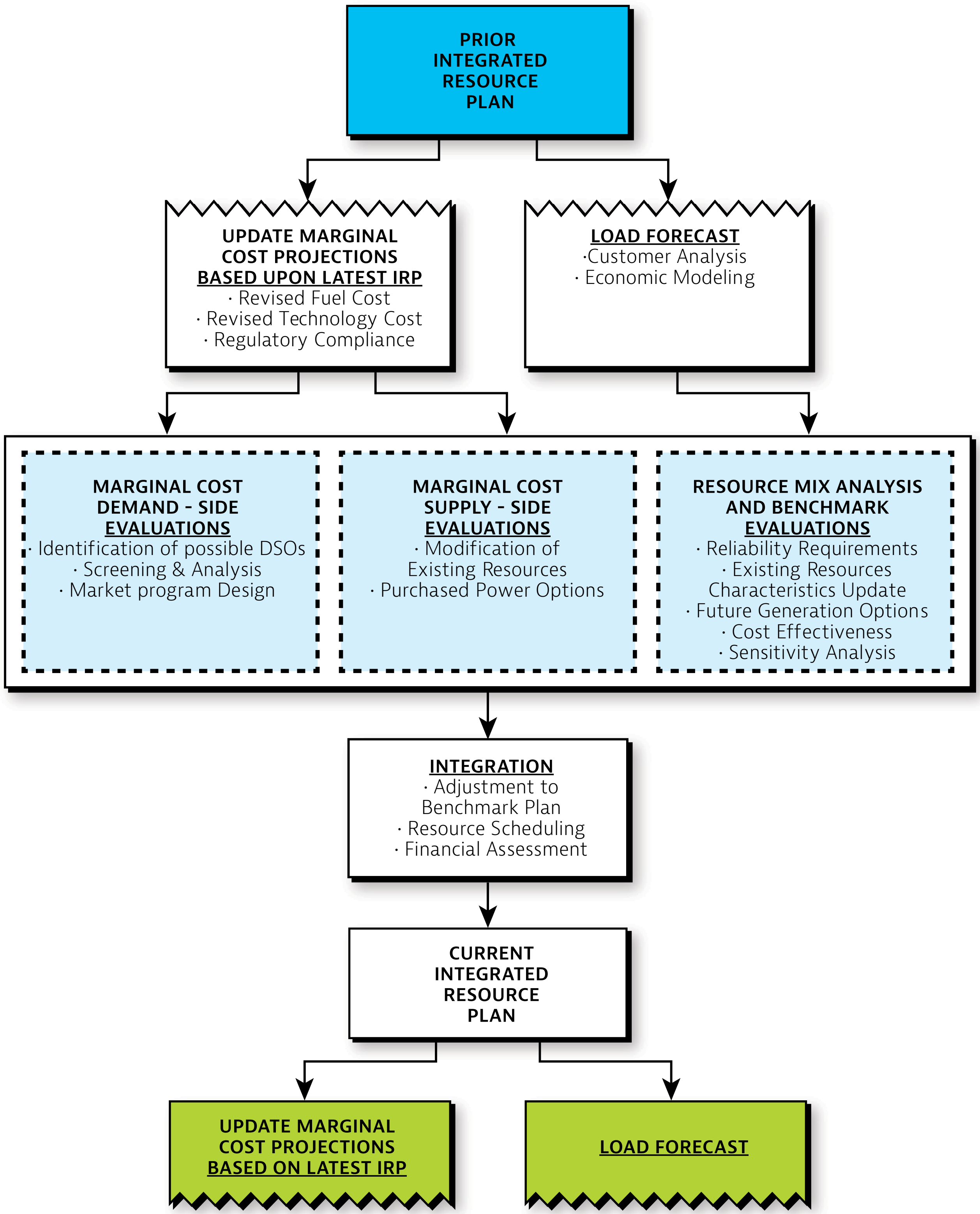
The integrated resource planning process is designed to identify the timing, amount and types of resources necessary to serve the long-term energy and demand requirements of Alabama Power's customers. Aided by the IRP, the Company is able to develop an effective resource strategy that is reasonably expected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

The 2022 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.

The IRP process includes several sequential steps, ultimately leading to the development of a resource needs determination, the production of generic expansion plans (sometimes referred to as a Benchmark Plan), and marginal energy cost forecasts that inform a variety of planning decisions. When developing the IRP, the Company begins by establishing reliability criteria while assessing the System's overall reliability needs. During this step, the Company establishes seasonal target reserve margins or TRMs that define the appropriate level of reliability for the System. The Company then applies these reliability criteria to the demand and energy forecasts to determine the amount and type of capacity that is required to meet forecasted conditions. The amount of capacity required is compared to existing, planned and committed resources. This comparison results in a needs determination, which establishes the amount and timing of capacity needs. After these steps, the Company performs an expansion planning analysis that determines the optimal least-cost resource mix, or the Benchmark Plan. This analysis provides a roadmap of potential options to meet future needs, and also serves as a basis for the development of more detailed production cost modeling.

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

FIGURE IV-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 (also referred to as demand-side options, or "DSO") programs 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 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 seasonal target reliability guidelines. 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. 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 generic expansion or Benchmark Plan that identifies the most cost-effective combination of options, which in turn informs the Company's decision-making as it pursues the acquisition or development of specific 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. Criteria also are established that qualify and quantify an appropriate level of capacity reserves in both the summer and winter seasons. These TRMs 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 TRMs, which are periodically reviewed and re-evaluated, are based on risk-adjusted economic analyses, operating experience and system operation input, and seek 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 IV.D), the 2022 IRP utilizes a minimum long-term Summer TRM of 16.25 percent and a minimum long-term Winter TRM of 26 percent. By virtue of load diversity across the System, the Summer TRM can be met if each Operating Company maintains a long-term summer reserve margin of at least 15.28 percent. Similarly, the Winter TRM can be met if each Operating Company maintains a long-term winter reserve margin of at least 25.18 percent. In other words, Alabama Power can maintain a long-term winter reserve margin of 25.18 percent but realize a level of reliability equivalent to 26 percent, thereby avoiding the cost of building or purchasing additional resources associated with the 0.82 percent differential. These capacity savings represent one of the many recognized benefits of operating as part of the Southern Pool.

Integration

Demand-side and supply-side options identified as cost-effective choices for resource additions, but not previously reflected in a prior 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. Many evaluations are performed concurrently. Marginal cost evaluations can be performed or updated at several points in the process. Figure IV-A-2 describes a typical chronological progression.

FIGURE IV-A-2: IRP Development Activities

Marginal Cost Projection Update
Preliminary Fuel Price Workshop
Supply-Side Technology Issues Reviewed
DSM Screening Analysis
Planning Issues Identified
Preliminary Planning Assumptions Established
Preliminary Fuel Forecasts
Technology Panel Review
Candidate Unit Assumptions Established
DSM Forecast Finalized
Load Forecast Finalized
Planning Assumptions Reviewed and Finalized
Resource Mix Analysis Process
Preliminary IRP Review
Benchmark Plan Completed
Financial Assessment
IRP Approval

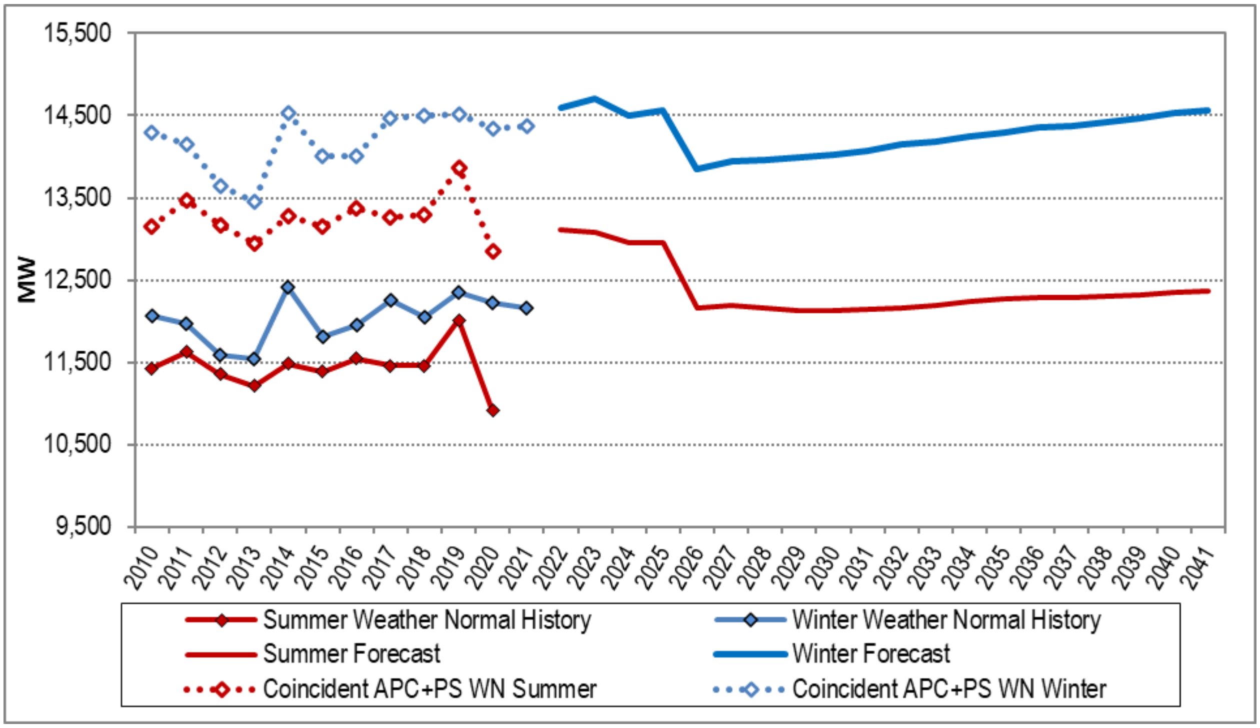
IV.B. LOAD FORECAST

The Company annually produces a 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). Underlying this load forecast are economic data and forecasts supplied by S&P Global (formerly IHS Markit). This information includes available employment and demographic data as well as other economic indicators for the state of Alabama, all of which support the development of econometric models used to forecast the number of customers. The other major input, customer electricity consumption, is less correlated with economic growth and more related to trends in increased efficiency and other factors. Taken together, these inputs indicate an overall decline in electricity usage for the Residential and Commercial classes.

The 2022 IRP also includes the Coordinated Planning and Operations Agreement with PowerSouth. Under the terms of the agreement, PowerSouth load and generating resources are included with Alabama Power load and resources for a combined economic dispatch of all resources. The PowerSouth energy sales are approximately 9,200 GWh, or an additional peak load of 2,300 MW to Alabama Power's forecasted winter peak demand.

Figure IV-B-1 represents the Company's actual weather normal summer and winter peak demands since 2010. Because the Peak Demand Forecast now includes PowerSouth load, an estimate of the coincident peak for both systems is included for both seasons. The graph also illustrates the projected winter and summer peak demands for Alabama Power and PowerSouth for 2022-2041, along with their respective growth rates. In 2024 and 2026, there is a projected loss of wholesale load due to the expiration of certain existing contracts. For the summer, there is an expected average annual demand growth of approximately 0.34 percent from 2021 through 2026 and approximately 0.11 percent from 2026 through 2041. For the winter peak demand, there is an expected average growth rate of 2.6 percent from 2021 to 2026 and approximately 0.34 percent from 2026 through 2041. These projected rates are higher than those shown in the 2019 IRP, and reflect the effects of stronger economic growth in the near term and, over the long term, the referenced loss of wholesale contracts and greater penetration of appliance and lighting efficiencies.

FIGURE IV-B-1: ALABAMA POWER WEATHER NORMALIZED HISTORICAL PEAK DEMAND WITH FORECAST



Year	Winter Peak Demand (MW)	Growth	Summer Peak Demand (MW)	Growth
2021	12,162*		11,953**	
2022	14,597	20.02%	13,105	9.64%
2023	14,703	0.73%	13,086	-0.14%
2024	14,506	-1.34%	12,946	-1.07%
2025	14,557	0.35%	12,950	0.03%
2026	13,846	-4.88%	12,156	-6.13%
2027	13,941	0.69%	12,198	0.35%
2028	13,967	0.19%	12,156	-0.34%
2029	13,985	0.13%	12,130	-0.21%
2030	14,019	0.24%	12,122	-0.07%
2031	14,072	0.38%	12,144	0.18%
2032	14,145	0.52%	12,167	0.19%
2033	14,180	0.25%	12,197	0.25%
2034	14,243	0.44%	12,234	0.30%
2035	14,296	0.37%	12,265	0.25%

Year	Winter Peak Demand (MW)	Growth	Summer Peak Demand (MW)	Growth
2036	14,355	0.41%	12,285	0.16%
2037	14,379	0.17%	12,294	0.07%
2038	14,417	0.26%	12,302	0.07%
2039	14,462	0.31%	12,320	0.15%
2040	14,529	0.46%	12,345	0.20%
2041	14,565	0.25%	12,367	0.18%

*The demand shown for Winter 2021 reflects weather normalized historical values without PowerSouth.
**The demand shown for Summer 2021 reflects forecasted values for September 2021 with PowerSouth.

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.

IV.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 for application to business case analyses and other appropriate decisions. Short-term forecasts are updated monthly as part of the Company's fuel budgeting process and marginal pricing dispatch procedures. For its long-term fuel price forecasts, the Company adopts fuel price projections that are developed each year by the US Energy Information Administration (EIA) for its Annual Energy Outlook (AEO).

The AEO presents several scenarios. Each scenario is the result of analysis conducted using the National Energy Modeling System (NEMS), an integrated multi-sector model simulating the evolution of the United States energy economy to 2050 under different sets of input assumptions. For its views of future prices of natural gas, coal and oil, the Company adopts the results from three of these scenarios—the Reference case, the High Oil and Gas Supply case and the Low Oil and Gas Supply case. Within each scenario, the fuel price paths are consistent with one another and with expected supply and demand feedbacks across key markets and regions of the economy. This 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 overall fuel supply outlooks shape the disposition of economic output across sectors.

IV.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 unpredictable events such as equipment failures or extreme weather. Reserve planning is performed on both a short-term and longer-term basis, as uncertain increases with time and 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, and notwithstanding unpredictable conditions that can affect customer demand. Such conditions include the following:

- **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 14.9 percent higher in a hot summer year and 19.6 percent higher in a cold winter year than in an average year.

- **Load Forecast:** 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 to actual variances, peak demand may grow by 4.9 percent more than expected over a four- to five-year period.

- **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 more than 10 percent 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 short-term System resource adequacy issue can vary. In general, having access to neighboring regions with load and resource diversity enhances reliability. 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").

Defining Target Reserve Margins

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

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

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

The Winter TRM 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 (TRMs)

After analyzing the load forecast and weather uncertainties, the cost of expected unserved energy, and the projected generation reliability of the System in the 2021 Reserve Margin Study, the Company is maintaining the current 16.25 percent long-term TRM for summer peak planning, and the current 26 percent long-term TRM for winter peak planning.

For the short-term, the Company is maintaining the Summer TRM of 15.75 percent, with a commensurate short-term Winter TRM of 25.5 percent.

The Winter TRM remains higher than the Summer TRM due to continued reliability risks that are unique to the winter season. The primary drivers for winter risk include: (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; (5) increased risk of fuel delivery disruption due to winter conditions; and (6) decreased supply alternatives from the wholesale power markets.

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 otherwise required by the System target. Thus, the diversified Summer TRM that applies to Alabama Power is 15.28 percent over the long-term and 14.78 percent over the short-term. Similarly, the Company's diversified Winter TRM is 25.18 percent over the long-term and 24.69 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 IV-D-1 depicts the projected diversified 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 slightly below both its diversified long-term Winter TRM (25.18 percent) and its diversified short-term Winter TRM (24.69 percent) for the planning timeframe (except 2026), with action to address these deficits likely needed by no later than the 2029 timeframe. To this end, while the Southern Pool affords the participants the ability to rely on temporary surpluses 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. In this regard, near-term deficit levels shown for Alabama Power in 2022 and 2023 largely resolve beginning in 2024 as resources previously identified by the Company and certificated by the APSC become available for retail service. The figure also shows the Company to be periodically above its Summer TRM. Figure IV-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 any corresponding shortfalls occurring during summer periods shown on Figure IV-D-3.

FIGURE IV-D-1: ALABAMA POWER PROJECTED SEASONAL RESERVE MARGINS

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Winter	11.8%	11.8%	24.0%	23.6%	25.9%	24.7%	24.6%	20.7%	20.5%	20.0%
Summer	20.5%	33.3%	34.8%	33.8%	39.1%	37.3%	38.1%	34.1%	34.2%	33.3%

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Winter	18.9%	18.1%	17.2%	14.2%	10.2%	7.4%	0.8%	-1.1%	-8.9%	-14.9%
Summer	33.1%	32.4%	31.5%	28.2%	24.6%	14.5%	14.5%	12.5%	3.8%	-10.0%

FIGURE IV-D-2: ALABAMA POWER PROJECTED WINTER CAPACITY NEEDS

Capacity Need (MW) - Winter		
Year	APC Reserve Margin (%)	APC NEED (MW)
2022	11.8%	1,882
2023	11.8%	1,895
2024	24.0%	106
2025	23.6%	226
2026	25.9%	(98)
2027	24.7%	63
2028	24.6%	78
2029	20.7%	621
2030	20.5%	664
2031	20.0%	729
2032	18.9%	894
2033	18.1%	1,000
2034	17.2%	1,144
2035	14.2%	1,577
2036	10.2%	2,145
2037	7.4%	2,564
2038	0.8%	3,509
2039	-1.1%	3,808
2040	-8.9%	4,948
2041	-14.9%	5,831

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

Capacity Need (MW) - Summer		
Year	**APC Reserve Margin (%)**	**APC NEED (MW)**
2022	20.5%	(753)
2023	33.3%	(2417)
2024	34.8%	(2592)
2025	33.8%	(2396)
2026	39.1%	(2890)
2027	37.3%	(2691)
2028	38.1%	(2772)
2029	34.1%	(2283)
2030	34.2%	(2292)
2031	33.3%	(2193)
2032	33.1%	(2166)
2033	32.4%	(2084)
2034	31.5%	(1985)
2035	28.2%	(1581)
2036	24.6%	(1144)
2037	14.5%	90
2038	14.5%	98
2039	12.5%	343
2040	3.8%	1411
2041	-10.0%	3121

IV.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 and disruptions. In general terms, a resilient electric system can withstand and mitigate the effects of disruptive events, including their magnitude and duration, through the ability to anticipate, adapt to, and recover from such an event. The Company has an excellent track record 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 generation fleet continues to evolve, there is the need for increased attentiveness to the management of fuel transportation and resource availability risk inherent in the provision of reliable electric service to customers. Additionally, the threat of high-impact, low probability events, such as physical and cyber-attacks, continues to grow. Given society's dependence on electricity, it is even more important that the Company remain vigilant in its commitment to maintaining a robust and resilient electric system.

IV.F. DEVELOPMENT OF INDICATIVE RESOURCE ADDITIONS

The Company's expansion planning analysis identifies an optimal mix of resources that satisfy future capacity and energy demands in an economic and reliable manner. In this step of the planning process, demand-side resources are integrated with supply-side resources to provide a roadmap that informs long-term resource planning decisions. Significantly, a generic expansion plan (i.e., the Benchmark Plan) does not represent a resource planning decision by the Company, but rather an indicative schedule of what the IRP has determined to be the optimal mix of resources.

As such, the purpose of the expansion planning process is to evaluate capacity and energy resource options to meet reliability needs across a wide range of potential future scenarios. To develop the expansion plan, the generation technologies that pass detailed screening are further evaluated using the AURORA production cost model, which is widely used throughout the electric industry. AURORA employs a generation mix optimization module that includes the following major inputs: (1) load forecast; (2) existing, planned and committed resources; (3) fuel prices; (4) emission costs; (5) future generating unit characteristics and capital cost; (6) capital recovery rates necessary to recover investment cost; (7) capital cost escalation rates; and (8) a discount rate. The AURORA model considers all possible combinations of capacity additions, on a yearly basis, that satisfy the Company's TRMs. The resulting combination of candidate resources with the smallest production and capital cost over the planning horizon represents the least-cost plan.

The output of the AURORA model serves as the primary guide in developing a generic expansion plan for the retail Operating Companies. This plan identifies the optimal capacity and energy additions that inform the type of capacity and energy resources that are most economical within a particular timeframe for the given assumptions.

Summary of Inputs and Assumptions:

The expansion planning process incorporates a wide range of inputs and assumptions, including, but not limited to, reliability criteria, load and energy forecasts, and numerous financial and economic scenarios.

- **Reserve Margin** — The 2022 IRP reflects a 16.25 percent System Summer TRM and a 26 percent System Winter TRM for long-term resource planning decisions.

- **Economic Forecast** — S&P Global's macroeconomic forecast serves as the basis for inflation and cost of capital estimates.

- **Load and Energy Forecasts** — The Budget 2022 Peak Demand and Energy Forecasts discussed in Section IV-B were utilized for the Company's 2022 IRP generic expansion plan.

- **Fuel Forecast** — The 2022 IRP generic expansion plan incorporates the fuel forecast information described in Section IV-C.

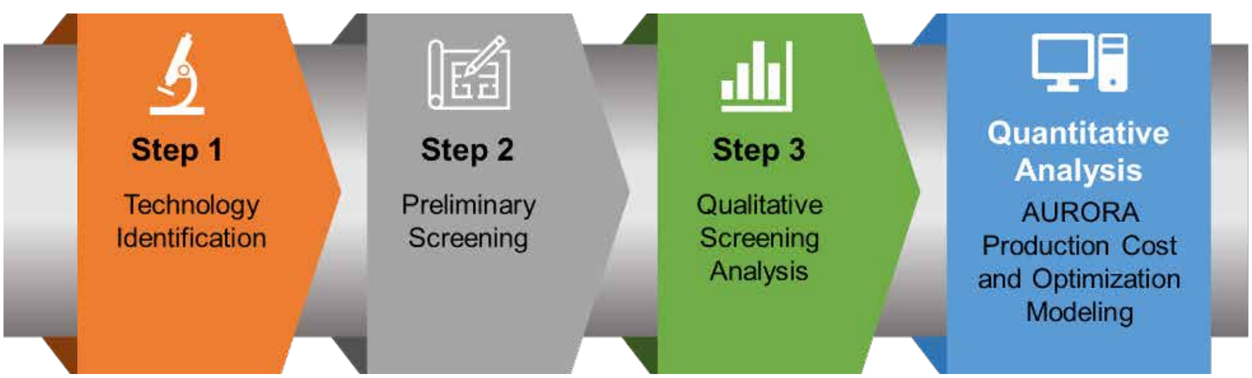
- **Financial Cost and Escalation** — The Company assumes that long-term debt and common stock are issued to finance the construction of generating units. The associated costs can fluctuate due to changes in market conditions (e.g., business risk perception, inflation rates and interest rates). Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term.

IV.G. TECHNOLOGY SCREENING

The Company performs detailed expansion planning and production cost analysis during each IRP. In connection with this effort, the Company completes a screening assessment of new generation technologies to identify a manageable list of potential supply-side technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) Technology Identification; (ii) Preliminary Screening; and (iii) Detailed Qualitative Screening. Supply-side options identified through this process are then considered in more detailed expansion plan modeling.

FIGURE IV-G-1: Technology Screening Process



As electricity generating technology is always evolving, the Company's screening process identifies those technologies that have the greatest possibility of serving a cost-effective role in the System during the modeling horizon. Even among the technologies that might play such a role, there remains uncertainty about the cost of each technology relative to its expected productivity and other technology options.

For Budget 2022 analyses, the technologies identified as potentially cost-effective included natural gas combined cycle (with and without carbon capture), natural gas combustion turbine (with and without selective catalytic reduction (SCR) systems), reciprocating internal combustion engines, solar photovoltaic, wind and battery storage. As appropriate, the Company also considers site-specific options that likewise could prove to be a cost-effective solution for customers.

Natural Gas Combined Cycle (NGCC): The Company's current assumption for planning purposes is that NGCC plants without carbon capture facilities are available for fleet expansion only through 2039. Another planning assumption is that beginning in 2040 new NGCC plants must capture 90 percent of their carbon dioxide emissions. The timing of this assumption is based on the Company's understanding of the Clean Air Act and corresponding regulations as they exist today, along with the applicable schedule for review of abatement technologies and emission control requirements (i.e., New Source Performance Standards and Best Available Control Technology).

Natural Gas Combustion Turbines (CT): The Company's current assumption for planning purposes is that CTs are available for fleet expansion through 2034. Beginning in 2035, new CTs must significantly reduce their NOx emissions through the installation of SCR. The timing of this assumption comes from the Company's understanding of the Clean Air Act and corresponding regulations as they exist today, along with the applicable schedule for review of abatement technologies and emission control requirements.

Reciprocating Internal Combustion Engine (RICE): RICE resources are available as an expansion option beginning in the year of capacity need for each scenario. The Company's current assumption for planning purposes is that RICE resources use liquid or gaseous fuel to produce power.

Solar PV: Solar PV with single-axis tracking is available as an expansion resource option beginning in 2025.

Wind: Wind turbines are available as an expansion resource beginning in the year of capacity need for each scenario.

Battery storage: Battery storage is available as an expansion resource beginning in the year of capacity need for each scenario.

For the 2022 IRP, the process described above yielded the following benchmark plan for Alabama Power. As shown, the plan calls for the addition of CT resources totaling 780 MW for the next ten years through 2031.

FIGURE IV-G-2: ALABAMA POWER WINTER BENCHMARK PLAN

Winter Benchmark Base Case with Generic Additions						
Year	**APC CT**	**APC NGCC**	**APC Battery Storage**	**APC Solar PV**[1]	**APC RM**	**APC Needs (MW)**
2022	-	-	-	-	11.8%	1,882
2023	-	-	-	-	11.8%	1,895
2024	-	-	-	-	24.0%	106
2025	-	-	-	-	23.6%	226
2026	-	-	-	-	25.9%	(98)
2027	-	-	-	-	24.7%	63
2028	-	-	-	-	24.6%	78
2029	690	-	-	-	25.7%	(69)
2030	90	-	-	-	26.0%	(116)
2031	-	-	-	-	25.5%	(51)
2032	180	-	-	-	25.7%	(66)
2033	180	-	-	-	26.2%	(140)
2034	120	-	-	-	26.0%	(116)
2035	-	390	-	-	25.7%	(73)
2036	-	600	-	-	25.9%	(105)
2037	-	360	-	-	25.5%	(46)
2038	-	1,050	-	-	26.2%	(151)
2039	-	330	-	-	26.4%	(182)
2040	720	-	600	-	25.6%	(62)
2041	900	-	-	570	25.7%	(79)

[1] New APC Solar PV is an energy only resource option.

The indicative addition of 780 MW of CTs is designed to address the capacity shortfall largely created by the planned retirement of Gaston Units 1-4 by the end of 2028, in order to comply with the 2020 ELG Rule. To address this anticipated capacity shortfall, the Company will need to investigate capacity replacement options. Corresponding efforts likely will include the issuance of a Request for Proposals (RFP), as well as the development of cost estimates for potential Company self-build or turnkey projects. To ensure all cost-effective options are preserved, in the interest of its customers, the Company expects to begin these and related efforts as early as 2023.

V. CONCLUSION

The 2022 IRP process reflected in this report yields the Company's resource adequacy projections for the current 20-year horizon. This identification includes both short- and long-term capacity deficits for Alabama Power, with the former largely addressed through the resources approved in Docket Nos. 32953 and 33182. Consistent with its obligation to provide reliable service to its customers, the Company intends to initiate appropriate measures to resolve its long-term 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 duties and responsibilities.

APPENDIX 1

ALABAMA POWER COMPANY
EXISTING SUPPLY-SIDE RESOURCES

FIGURE A1-1

Alabama Power Company
Existing Supply-Side Resources
(as of January 2022)

Alabama Power Company Owned & Contracted Resource Summary						
	Plants	Units	Nameplate/ Contract Capacity (MW)	IRP Summer Capacity (MW)	IRP Winter Capacity (MW)	
Fossil	9	31	7,837	7,896	8,128	
Nuclear	1	2	1,720	1,781	1,781	
Hydro	14	41	1,668	1,695	1,656	
Solar	2	2	18	4	1	
Ownership Total	***26***	***76***	***11,243***	***11,375***	***11,566***	
Contracted Total	***N/A***	***N/A***	***4,619***	***4,420***	***4,754***	
Total Owned & Contracted			***15,862***	***15,795***	***16,320***	

Fossil Steam Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Barry	1	125	80	80	1954	Barry 1 restored to active service in 2019
	2	125	80	80	1954	Barry 2 restored to active service in 2019
	3					Barry 3 retired on August 24, 2015
	4	350	362	362	1969	
	5	700	757	757	1971	
Gadsden	1	60	0	17	1949	
	2				1949	Gadsden 2 unavailable after Spring 2019
Gaston	1	125	127	127	1960	Ratings reflect 50% Alabama Power capacity entitlement
	2	125	128	128	1960	Ratings reflect 50% Alabama Power capacity entitlement
	3	125	127	127	1961	Ratings reflect 50% Alabama Power capacity entitlement
	4	125	128	128	1962	Ratings reflect 50% Alabama Power capacity entitlement
	5	880	832	832	1974	
Greene County	1	150	155	155	1965	Ratings reflect Alabama Power 60% ownership
	2	150	155	155	1966	Ratings reflect Alabama Power 60% ownership
Miller	1	606	632	632	1978	Ratings reflect Alabama Power 91.8% ownership
	2	606	636	636	1985	Ratings reflect Alabama Power 91.8% ownership
	3	660	693	693	1989	
	4	660	704	704	1991	
Total	**16**	**5,572**	**5,596**	**5,613**		

Nuclear Steam Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Farley	1	860	897	897	1975	
	2	860	884	884	1979	
Total	**2**	**1,720**	**1,781**	**1,781**		

Alabama Power Company Supply-Side Resource Summary - cont.

Gas-Fired Plants (Combustion Turbines)						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Greene County	2	80	84	100	1996	
	3	80	82	98	1996	
	4	80	81	97	1995	
	5	80	82	98	1995	
	6	80	81	97	1995	
	7	80	80	96	1995	
	8	80	83	99	1996	
	9	80	82	98	1996	
	10	80	85	101	1996	
Total	**9**	**720**	**740**	**884**		

Gas-Fired Plants (Combined Cycles)						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Barry	6	535	569	594	2000	
	7	535	567	580	2001	
Washington County	1	123	100	107	1999	Cogeneration plant
Lowndes County	1	105	85	95	1999	Cogeneration plant
Theodore	1	236	231	245	2001	Cogeneration plant
Total	**5**	**1,535**	**1,552**	**1,621**		

Oil-Fired Plants (Combustion Turbines)						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Gaston	A	10	8	10	1970	Ratings reflect 50% Alabama Power capacity entitlement
Total	**1**	**10**	**8**	**10**		

Solar Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Fort Rucker		10.6	2.24	1	2017	
ANAD		7.4	1.63	1	2017	
Total	**2**	**18**	**4**	**1**		

Contracted Capacity						
Plant		**Contract Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**Start Year**	**Notes**
Calhoun Power PPA		700	632	708	2003	
Chisholm View PPA		202	48	62	2013	
Buffalo Dunes PPA		202	58	66	2014	
LaFayette PPA		72	18	4	2017	
Hog Bayou PPA		238	224	244	2020	
Other		3,205	3,440	3,670		Represents capacities through various contracts
Total		**4,619**	**4,420**	**4,754**		

Alabama Power Company Supply-Side Resource Summary - cont.

Hydroelectric Plants						
Plant	**Unit**	**Nameplate Capacity (MW)**	**IRP Summer Capacity (MW)**	**IRP Winter Capacity (MW)**	**In-Service Year**	**Notes**
Weiss	1	29	27	24	1962	Upper Coosa Group
	2	29	27	24	1961	Upper Coosa Group
	3	29	27	24	1961	Upper Coosa Group
Henry	1	24	24	23	1966	Upper Coosa Group
	2	24	24	23	1966	Upper Coosa Group
	3	24	24	23	1966	Upper Coosa Group
Logan Martin	1	45	43	40	1964	Upper Coosa Group
	2	45	43	40	1964	Upper Coosa Group
	3	45	43	40	1964	Upper Coosa Group
Lay	1	30	30	30	1968	Lower Coosa Group
	2	30	30	30	1968	Lower Coosa Group
	3	30	30	30	1967	Lower Coosa Group
	4	30	30	30	1967	Lower Coosa Group
	5	30	30	30	1967	Lower Coosa Group
	6	30	30	30	1967	Lower Coosa Group
Mitchell	4	20	19	19	1949	Lower Coosa Group
	5	50	48	49	1985	Lower Coosa Group
	6	50	48	49	1985	Lower Coosa Group
	7	50	48	49	1985	Lower Coosa Group
Jordan	1	25	32	33	1928	Lower Coosa Group
	2	25	32	33	1928	Lower Coosa Group
	3	25	32	33	1928	Lower Coosa Group
	4	25	32	33	1928	Lower Coosa Group
Bouldin	1	75	75	75	1967	Lower Coosa Group
	2	75	75	75	1967	Lower Coosa Group
	3	75	75	75	1967	Lower Coosa Group
Martin	1	46	46	44	1926	Tallapoosa Group
	2	41	41	39	1926	Tallapoosa Group
	3	40	40	38	1926	Tallapoosa Group
	4	55	55	52	1952	Tallapoosa Group
Thurlow	1	34	34	33	1930	Tallapoosa Group
	2	34	34	33	1930	Tallapoosa Group
	3	13	13	12	1930	Tallapoosa Group
Yates	1	24	22	23	1928	Tallapoosa Group
	2	24	22	23	1928	Tallapoosa Group
Harris	1	66	67	62	1983	Tallapoosa Group
	2	66	67	62	1983	Tallapoosa Group
Smith	1	79	89	88	1961	Warrior Group
	2	79	89	88	1962	Warrior Group
Bankhead	1	54	53	53	1963	Warrior Group
Holt	1	47	48	48	1968	Warrior Group
Total	**41**	**1,668**	**1,695**	**1,656**		

APPENDIX 2

ALABAMA POWER COMPANY

DEMAND SIDE MANAGEMENT PROGRAMS

Alabama Power Company implements DSM measures and programs that are designed to assist with system load shape management (thereby reducing costs and the need for future capital investment), while also promoting the efficient use of energy by the Company's customers. 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. As with existing programs, new programs must be expected to benefit all customers, thereby avoiding a situation where some customers are effectively being caused to subsidize the benefits realized by others.

Alabama Power currently has customers participating in more than 18 DSM programs in the residential, commercial and industrial sectors, as well as programs managed through the Company's Distribution Operations. The 2022 IRP includes approximately 1,523 MW of existing contracted active demand-side programs that have allowed the deferral of 1,102 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 recognition of capacity equivalence under DSM program, as compared to a supply-side resource. DSM programs subject to the direct control of the Company (e.g., non-residential interruptible load) are called "active DSM." 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 their effects are embedded in the Company's load forecast. Existing passive DSM programs are estimated to result in a winter peak load reduction of 158 MW. The total amount of existing DSM programs reflected in the 2022 IRP is 1,681 MW—1,523 MW (active) and 158 MW (passive).

The Company has recently expanded its available DSM programs and measures to provide up to 200 MW of demand side resources by 2025 to offset a portion of its winter peak demand. These programs span all three customer classes (residential, commercial and industrial) and cover a variety of customer segments. The contemplated portfolio comprises five (5) primary categories:

- Beneficial Electrification – installation of electric end-use products that save customers money over time and improve customers' quality of life, while also benefiting the electric grid

- Customer Rebates and Incentives – monetary benefits for customers who implement energy efficient behaviors or products

- Load Optimization/Next Generation Demand Response – programs designed to shift demand away from critical peak periods without sacrificing customer comfort

- Low-to-Moderate Income/Income Qualified – weatherization, direct installations and thermostat programs for residential customers who meet specific income qualifications

- Traditional Curtailment/Demand Response – load-reduction programs based on contractual agreements with customers to reduce their demand during critical periods

As part of the development of these programs, Alabama Power partnered with Cadmus, a strategic and technical consulting firm, to outline possible programs based on customer insights, demand response potential, and customer adoption. The resulting analysis helped illustrate a forecast scenario of incremental demand response potential for both summer and winter seasons, associated cost estimates for residential, commercial and industrial programs, and key assumptions for event peak demand reductions, customer eligibility requirements, and program and event participation.

Alabama Power's expanded portfolio of programs and pilots will incorporate new and expanded marketing and outreach efforts that utilize customers' preferred communication channels, while addressing perceived barriers and recognized motivations to expand customer interest and participation in programs that help build customer knowledge. Additionally, Alabama Power will consider marketing approaches that address specific low-to-moderate income needs and barriers, such as a focus on demand response benefits that can be realized without the need for costly investment in equipment.

ACTIVE DSM PROGRAMS

The capacity values associated with the Company's active DSM programs, as reflected in the 2022 IRP, are shown in Figure A2-1 Winter and Figure A2-1 Summer.

Figure A2-1 Winter

INTEGRATED RESOURCE PLAN 2022

Projections of Active Demand-Side Options (DSOs) 2022-2041

Active DSOs

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Contract Amounts	**(1,523)**	**(1,526)**	**(1,746)**	**(1,761)**	**(1,761)**	**(1,920)**	**(1,921)**	**(1,921)**	**(1,921)**	**(1,922)**
Resource Deferral Amounts	**(1,102)**	**(1,112)**	**(1,265)**	**(1,279)**	**(1,280)**	**(1,392)**	**(1,393)**	**(1,393)**	**(1,393)**	**(1,394)**

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Contract Amounts	**(1,923)**	**(1,923)**	**(1,924)**	**(1,925)**	**(1,925)**	**(1,926)**	**(1,926)**	**(1,927)**	**(1,928)**	**(1,928)**
Resource Deferral Amounts	**(1,395)**	**(1,395)**	**(1,396)**	**(1,397)**	**(1,397)**	**(1,398)**	**(1,398)**	**(1,399)**	**(1,400)**	**(1,400)**

Active DSOs - Contract Amounts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(1,173)	(1,157)	(1,371)	(1,374)	(1,374)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)
600 Hour Interruptible	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)
Non-Indust. Direct Load Control	0	(2)	(7)	(14)	(23)	(30)	(30)	(30)	(30)	(30)
Customer Standby Generation	(8)	(23)	(26)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Distribution Regulation Option Program (DROP)	(138)	(140)	(138)	(138)	(130)	(131)	(132)	(132)	(132)	(133)
Total Active DSO - Contract Amount	(1,523)	(1,526)	(1,746)	(1,761)	(1,761)	(1,920)	(1,921)	(1,921)	(1,921)	(1,922)

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)
600 Hour Interruptible	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)
Non-Indust. Direct Load Control	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Customer Standby Generation	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Distribution Regulation Option Program (DROP)	(134)	(134)	(135)	(136)	(136)	(137)	(137)	(138)	(139)	(139)
Total Active DSO - Contract Amount	(1,923)	(1,923)	(1,924)	(1,925)	(1,925)	(1,926)	(1,926)	(1,927)	(1,928)	(1,928)

Active DSOs - Resource Deferral Amounts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(806)	(795)	(943)	(945)	(945)	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)
600 Hour Interruptible	(141)	(141)	(141)	(141)	(141)	(141)	(141)	(141)	(141)	(141)
Non-Indust. Direct Load Control	0	(2)	(7)	(15)	(24)	(32)	(32)	(32)	(32)	(32)
Customer Standby Generation	(8)	(24)	(28)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
Distribution Regulation Option Program (DROP)	(147)	(149)	(147)	(147)	(139)	(140)	(141)	(141)	(141)	(142)
Total Active DSO - Resource Deferral Amount	(1,102)	(1,112)	(1,265)	(1,279)	(1,280)	(1,392)	(1,393)	(1,393)	(1,393)	(1,394)

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)	(1,048)
600 Hour Interruptible	(141)	(141)	(141)	(141)	(141)	(141)	(141)	(141)	(141)	(141)
Non-Indust. Direct Load Control	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
Customer Standby Generation	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
Distribution Regulation Option Program (DROP)	(143)	(143)	(144)	(145)	(145)	(146)	(146)	(147)	(148)	(148)
Total Active DSO - Resource Deferral Amount	(1,395)	(1,395)	(1,396)	(1,397)	(1,397)	(1,398)	(1,398)	(1,399)	(1,400)	(1,400)

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 2022 IRP.

Figure A2-1 Summer

INTEGRATED RESOURCE PLAN 2022

Projections of Active Demand-Side Options (DSOs) 2022-2041

Active DSOs

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Contract Amounts	(1,500)	(1,700)	(1,739)	(1,750)	(1,898)	(1,905)	(1,905)	(1,904)	(1,904)	(1,905)
Resource Deferral Amounts	(1,026)	(1,162)	(1,188)	(1,198)	(1,291)	(1,295)	(1,295)	(1,294)	(1,294)	(1,295)

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Contract Amounts	(1,905)	(1,905)	(1,906)	(1,906)	(1,906)	(1,906)	(1,907)	(1,907)	(1,907)	(1,907)
Resource Deferral Amounts	(1,295)	(1,295)	(1,296)	(1,296)	(1,296)	(1,296)	(1,298)	(1,298)	(1,298)	(1,298)

Active DSOs - Contract Amounts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(1,157)	(1,340)	(1,374)	(1,374)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)
600 Hour Interruptible	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)
Non-Indust. Direct Load Control	(5)	(6)	(10)	(16)	(24)	(30)	(30)	(30)	(30)	(30)
Customer Standby Generation	(8)	(23)	(26)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Distribution Regulation Option Program (DROP)	(126)	(126)	(124)	(125)	(116)	(116)	(116)	(115)	(115)	(116)
Total Active DSO - Contract Amount	(1,500)	(1,700)	(1,739)	(1,750)	(1,898)	(1,905)	(1,905)	(1,904)	(1,904)	(1,905)

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)
600 Hour Interruptible	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)	(205)
Non-Indust. Direct Load Control	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Customer Standby Generation	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Distribution Regulation Option Program (DROP)	(116)	(116)	(117)	(117)	(117)	(117)	(118)	(118)	(118)	(118)
Total Active DSO - Contract Amount	(1,905)	(1,905)	(1,906)	(1,906)	(1,906)	(1,906)	(1,907)	(1,907)	(1,907)	(1,907)

Active DSOs - Resource Deferral Amounts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(748)	(866)	(889)	(889)	(986)	(986)	(986)	(986)	(986)	(986)
600 Hour Interruptible	(132)	(132)	(132)	(132)	(132)	(132)	(132)	(132)	(132)	(132)
Non-Indust. Direct Load Control	(4)	(4)	(7)	(12)	(17)	(22)	(22)	(22)	(22)	(22)
Customer Standby Generation	(8)	(24)	(28)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
Distribution Regulation Option Program (DROP)	(134)	(134)	(132)	(133)	(124)	(124)	(124)	(123)	(123)	(124)
Total Active DSO - Resource Deferral Amount	(1,026)	(1,162)	(1,188)	(1,198)	(1,291)	(1,295)	(1,295)	(1,294)	(1,294)	(1,295)

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rate Real Time Pricing (RTP)										
150 & 200 Hour Interruptible	(986)	(986)	(986)	(986)	(986)	(986)	(986)	(986)	(986)	(986)
600 Hour Interruptible	(132)	(132)	(132)	(132)	(132)	(132)	(132)	(132)	(132)	(132)
Non-Indust. Direct Load Control	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
Customer Standby Generation	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
Distribution Regulation Option Program (DROP)	(124)	(124)	(125)	(125)	(125)	(125)	(126)	(126)	(126)	(126)
Total Active DSO - Resource Deferral Amount	(1,295)	(1,295)	(1,296)	(1,296)	(1,296)	(1,296)	(1,298)	(1,298)	(1,298)	(1,298)

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 2022 IRP.

PASSIVE DSM PROGRAMS

The projected load reductions associated with Company's passive DSM programs, as embedded in the load forecasts underlying the 2022 IRP, are shown in Figure A3–2 Winter and Figure A3–2 Summer.

Figure A2-2 Winter

INTEGRATED RESOURCE PLAN 2022
Projections of Passive Demand-Side Options (DSOs) 2022-2041

Gross Peak Load

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Peak (MW) Winter	14,755	14,886	14,699	14,760	14,059	14,165	14,184	14,230	14,275	14,338
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Peak (MW) Winter	14,422	14,468	14,543	14,608	14,680	14,716	14,764	14,817	14,891	14,934

Passive DSO Impacts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Energy Efficiency Programs	(153)	(158)	(164)	(169)	(175)	(180)	(169)	(192)	(197)	(203)
Commercial Energy Efficiency Programs	(5)	(10)	(11)	(12)	(13)	(15)	(16)	(17)	(18)	(20)
Industrail Energy Efficiency Programs	(0)	(15)	(19)	(22)	(25)	(29)	(32)	(36)	(40)	(44)
Peak (MW) Winter	(158)	(183)	(193)	(203)	(213)	(224)	(217)	(245)	(256)	(266)
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Residential Energy Efficiency Programs	(208)	(214)	(220)	(226)	(233)	(239)	(242)	(245)	(245)	(245)
Commercial Energy Efficiency Programs	(21)	(23)	(24)	(26)	(28)	(29)	(31)	(33)	(35)	(36)
Industrail Energy Efficiency Programs	(48)	(52)	(56)	(60)	(64)	(69)	(73)	(78)	(83)	(88)
Peak (MW) Winter	(277)	(288)	(300)	(312)	(325)	(337)	(347)	(355)	(362)	(369)

Net Peak Load

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Peak (MW) Winter	14,597	14,703	14,506	14,557	13,846	13,941	13,967	13,985	14,019	14,072
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Peak (MW) Winter	14,145	14,180	14,243	14,296	14,355	14,379	14,417	14,462	14,529	14,565

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 2022
Projections of Passive Demand-Side Options (DSOs) 2022-2041

Gross Peak Load

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Peak (MW) Summer	13,266	13,264	13,129	13,138	12,349	12,395	12,358	12,337	12,334	12,360
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Peak (MW) Summer	12,389	12,424	12,466	12,503	12,529	12,544	12,558	12,581	12,611	12,639

Passive DSO Impacts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Energy Efficiency Programs	(153)	(154)	(155)	(156)	(157)	(158)	(159)	(160)	(161)	(161)
Commercial Energy Efficiency Programs	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Industrail Energy Efficiency Programs	(0)	(17)	(20)	(24)	(27)	(31)	(35)	(39)	(43)	(47)
Peak (MW) Summer	(161)	(178)	(183)	(188)	(193)	(197)	(202)	(207)	(212)	(216)
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Residential Energy Efficiency Programs	(162)	(163)	(164)	(165)	(166)	(168)	(168)	(169)	(169)	(169)
Commercial Energy Efficiency Programs	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Industrail Energy Efficiency Programs	(51)	(56)	(60)	(65)	(69)	(74)	(79)	(84)	(89)	(94)
Peak (MW) Summer	(222)	(227)	(232)	(238)	(244)	(250)	(256)	(261)	(266)	(272)

Net Peak Load

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Peak (MW) Summer	13,105	13,086	12,946	12,950	12,156	12,198	12,156	12,130	12,122	12,144
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Peak (MW) Summer	12,167	12,197	12,234	12,265	12,285	12,294	12,302	12,320	12,345	12,367

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.

DESCRIPTION OF DSM PROGRAMS

Alabama Power's active and passive DSM program are identified below.

ACTIVE DSM PROGRAMS

Residential Demand Response

1. Centsable Switch (direct load control) – A cycling program whereby a customer's HVAC is cycled 67 percent during the months of June-September up to 5 hours per day, subject to a maximum of 150 hours per year.
2. SmartPower Critical Peak Pricing Program (price signal) – 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

3. Industrial Interruptible Program (contractual curtailment) – 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 15-30 minutes' notice. The Company's right to interrupt is subject to contractual limitations (e.g., no more than 200-600 hours per year and no longer than 8 hours per call).
4. Supplemental Reserves (contractual curtailment) – Less than 15-minute interruptible load that can be called as needed to support system operations.
5. Standby Generator Program (contractual curtailment) – Under this program, customers enter a contract with Alabama Power to switch to their standby generators 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.
6. Real Time Pricing (price signal) – Industrial pricing option based on marginal costs plus applicable components to recover fixed costs.

Transmission and Distribution

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

PASSIVE DSM PROGRAMS

Residential Load Management

8. Alabama Power Smart Advantage™ (load optimization) – A load optimization program that combines the Residential Time Advantage – Energy Only rate with customized heating/cooling schedules pushed to participants' smart thermostats. Schedules shift energy usage to pre-condition the home during off-peak "economy priced" periods and allow thermostat setpoints to drift within the customer's comfort band during "peak priced" periods. This program began as a small event-based pilot in December 2019 and has transitioned to a demand management program for both winter and summer.
9. Residential Time Advantage Rates (price signal) – Time Advantage Rates provide pricing signals by time period to incent customers to shift their usage to lower cost periods. Participants in the Alabama Power Smart Advantage program are not included in the load reduction calculated for being on a Time Advantage rate.
10. Family Dwelling – Demand (price signal) – This rate became available to customers in April 2022 and incorporates a demand charge during winter and summer season peak hours to incent customers to reduce load during that time.
11. Residential Plug-in Electric Vehicle Rate Rider (price signal) – 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 Energy Efficiency

12. Smart Thermostat Rebate Program – This program provides a rebate for customers who purchase and install qualifying smart thermostats in their homes. Smart thermostats help customers use energy more efficiently and reduce peak usage from their heating and cooling systems. While features vary, many smart thermostats allow customers to manage their energy usage remotely through an app or online platform and learn from customer behaviors and preferences.
13. 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 IECC would be given a HERS rating of 100. Each point of reduction in the HERS index represents a 1 percent increase in energy efficiency. Therefore, a Smart Neighborhood home is at least 35 percent 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.

14. Heat Pump Water Heater Program – This program promotes the installation of heat pump water heaters which use energy efficient heat pump technology to transfer heat from the surrounding environment to the water.
15. 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.
16. Online Energy Check-Up (education and awareness) – This program makes an on-line energy audit available to all residential customers.

Commercial & Industrial Load Management

17. Business Time Advantage Rates (price signal) – Time Advantage Rates provide pricing signals by time period to incent customers to shift their usage to lower cost periods.
18. Nighttime Capacity Rate Rider (price signal) – This rider offers billing options for customers whose nighttime capacities exceed those established during the day due to a significant portion of electric load being operated during nighttime hours.

Commercial & Industrial Energy Efficiency

19. Energy Star Cooking – This program promotes Energy Star cooking equipment in the commercial market.
20. Heat Pump Water Heater Program – This commercial program promotes heat pump water heaters, which use energy efficient heat pump technology to transfer heat from the surrounding environment to the water.

Transmission and Distribution

21. Distribution Energy Efficiency Program (DEEP) – DEEP operates continually using capacitors to reduce voltage drop on distribution feeders. The lower voltage upstream of distribution feeders lowers the demand and reduces reactive power requirements on the system.

DSM PILOTS

The Company is currently conducting the following pilot programs with limited numbers of participants within the residential class.

1. Residential Power Pause – The Power Pause pilot officially started on June 1, 2019. Due to the Covid-19 pandemic and resulting ongoing global supply chain constraints, the pilot was suspended in 2020. A resumption of the pilot is planned for the second or third quarter of 2023, with full program roll-out in late 2023 or 2024. The premise of 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 pilot phase of the program is limited to employees taking service from the Company and only applies to customers with a 200-amp service. The pilot allows the Company, using RCDC (remote connect/disconnect) meters, to interrupt electric service to participants subject to the following parameters:
    - Months – January to December
    - Total Annual Interruptible Hours – 40 Hours
    - Maximum Hours per Event – 4 Hours
    - Maximum Daily Events – 2 Events
    - Available Time Periods – Monday to 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. The goal of the pilot is to study electric water heating usage patterns of 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.
3. Residential EV Pilot – In 2021, Alabama Power partnered with FleetCarma to conduct a data collection pilot for electric vehicle drivers in the Company's service territory. Through this pilot, the Company gathered insights around charging behavior. In 2022, Alabama Power is partnering with EV.Energy to conduct pilot testing of different program concepts including charging optimization based on the plug-in electric vehicle rate rider and event-based load control through vehicle telematics systems. The current pilot phase is limited to 200 participants, with full program rollout expected in 2023.
4. Residential Income-qualified Smart Thermostat Pilot – Alabama Power is developing a program to help income-qualified participants manage their energy usage and use energy more efficiently. This program will focus on three main components: weatherization, efficient equipment/measures, and technology. The Company will launch this program

in phases, beginning with smart thermostat technology. Traditional rebate programs create barriers for income-qualified customers since they require customers to make upfront purchases and wait to be reimbursed. This program will provide a free smart thermostat and free direct installation to qualifying customers.

5. Residential Smart Thermostat Peak Optimization – In 2019, Alabama Power launched the Alabama Power Smart Advantage™ program as a small event-based pilot to combine a time-of-use rate with winter demand response events that included pre-heating in the hours prior to the events. Based on the success of those initial events, the Company transitioned to continuous load optimization that essentially runs events with pre-conditioning each weekday (excluding holidays) around the customer's time-of-use rate. In 2022, the Company plans to offer customers on both time-of-use rates and standard rates the opportunity to participate in demand response events during the winter and summer seasons, during which the smart thermostat technology will reduce peak load from heating and cooling during peak hours and shift it to off-peak hours through pre-conditioning. The Company plans full program deployment in 2023.

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.

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Alabama Power