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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period From ________________ to ________________

Commission File No. 333-192954

OglethorpePowerCorporation

(An Electric Membership Corporation)
(Exact name of registrant as specified in its charter)

Georgia	**58-1211925**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)
2100 East Exchange Place Tucker, Georgia	**30084-5336**
(Address of principal executive offices)	(Zip Code)
Registrant's telephone number, including area code:	**(770) 270-7600**
Securities registered pursuant to Section 12(b) of the Act:	**None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. **Yes** ☐ **No** ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes** ☐ **No** ☒

Indicate by check mark whether the registrant has submitted every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
			Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ☐ **No**☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. **The Registrant is a membership corporation and has no authorized or outstanding equity securities.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. **The Registrant is a membership corporation and has no authorized or outstanding equity securities.**

Documents Incorporated by Reference: **None**

OGLETHORPE POWER CORPORATION

2022 FORM 10-K ANNUAL REPORT

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CAUTIONARY STATEMENT REGARDING

FORWARD-LOOKING INFORMATION

This annual report on Form 10-K contains "forward-looking statements." All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as future capital expenditures, business strategy, regulatory actions, and development, construction or operation of facilities (often, but not always, identified through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "projection," "target" and "outlook") are forward-looking statements.

Although we believe that in making these forward-looking statements our expectations are based on reasonable assumptions, any forward-looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward-looking statements. Some of the risks, uncertainties and assumptions that may cause actual results to differ from these forward-looking statements are described under the heading "RISK FACTORS" and in other sections of this annual report. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this annual report may not occur.

Any forward-looking statement speaks only as of the date of this annual report, and, except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of them; nor can we assess the impact of each factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- cost increases and schedule delays with respect to our capital improvement and construction projects, such as, the construction of two additional nuclear units at Plant Vogtle and closure of coal ash ponds;
- the resolution of any disputes between two or more of the Vogtle co-owners, including the current litigation regarding certain cost-mitigation provisions under the ownership participation agreement;
- decisions made by the Georgia Public Service Commission in the regulatory process related to the two additional units at Plant Vogtle;
- a decision by Georgia Power Company to cancel the additional Vogtle units or a decision by more than 10% of the co-owners of the additional Vogtle units not to proceed with the construction of the additional Vogtle units upon the occurrence of certain material adverse events;
- the impact of regulatory or legislative responses to climate change initiatives or efforts to reduce greenhouse gas emissions, including carbon dioxide;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- our access to capital, the cost to access capital, and the results of our financing and refinancing efforts, including availability of funds in the capital markets;
- the continued availability of funding from the Rural Utilities Service;
- increasing debt caused by significant capital expenditures;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- actions by credit rating agencies;

- commercial banking and financial market conditions;
- the occurrence of certain events that give the Department of Energy the option to require that we repay all amounts outstanding under the loan guarantee agreement with the Department of Energy over a five-year period and its decision to require such repayment;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;
- adequate funding of our nuclear and coal ash pond decommissioning trust funds including investment performance and projected decommissioning costs;
- early retirement of our co-owned coal facilities;
- continued efficient operation of our generation facilities by us and third-parties;
- the availability of an adequate and economical supply of fuel, water and other materials;
- reliance on third-parties to efficiently manage, distribute and deliver generated electricity;
- the direct or indirect effect on our business resulting from cyber or physical attacks on us, our members or third-party service providers, vendors or contractors;
- acts of sabotage, wars or terrorist activities, including cyber attacks;
- changes in technology available to and utilized by us, our competitors, or residential or commercial consumers in our members' service territories, including from the development and deployment of distributed generation and energy storage technologies;
- future variants of the current coronavirus ("COVID-19") and any resulting economic disruption and its impact on our business, financial condition, operations, construction projects, including the additional units at Plant Vogtle, and our members and their service territories;
- the inability of counterparties to meet their obligations to us, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- our members' ability to offer their residential, commercial and industrial customers competitive rates;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption, energy conservation and efficiency efforts and the general economy;
- general economic conditions;
- weather conditions and other natural phenomena;
- litigation or legal and administrative proceedings and settlements;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- significant changes in critical accounting policies material to us;

- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards;
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events, or similar occurrences; and
- other factors discussed elsewhere in this annual report and in other reports we file with the SEC.

ITEM 1. BUSINESS

OGLETHORPE POWER CORPORATION

General

We are a Georgia electric membership corporation (an EMC) incorporated in 1974 and headquartered in metropolitan Atlanta. We are owned by our 38 retail electric distribution cooperative members. Our principal business is providing wholesale electric power to our members. As with cooperatives generally, we operate on a not-for-profit basis. We are one of the largest electric cooperatives in the United States in terms of revenues, assets, kilowatt-hour sales to members and, through our members, consumers served. We are also the second largest power supplier in the state of Georgia. We have 323 employees.

Our members are local consumer-owned distribution cooperatives that provide retail electric service on a not-for-profit basis. In general, our members' customer base consists of residential, commercial and industrial consumers within specific geographic areas. Our members serve approximately 2.1 million electric consumers (meters) representing approximately 4.4 million people. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES."

Our mailing address is 2100 East Exchange Place, Tucker, Georgia 30084-5336, and telephone number is (770) 270-7600. We maintain a website at *www.opc.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available on this website as soon as reasonably practicable after this material is filed with the Securities and Exchange Commission. Information contained on our website is not incorporated by reference into and should not be considered to be part of this annual report on Form 10-K.

Cooperative Principles

Cooperatives like Oglethorpe are business organizations owned by their members, which are also either their wholesale or retail customers. As not-for-profit organizations, cooperatives are intended to provide services to their members at the lowest possible cost, in part by eliminating the need to produce profits or a return on equity. Cooperatives may make sales to non-members, the effect of which is generally to reduce costs to members. Today, cooperatives operate throughout the United States in such diverse areas as utilities, agriculture, irrigation, insurance and banking.

All cooperatives are based on similar business principles and legal foundations. Generally, an electric cooperative designs its rates to recover its cost-of-service and to collect a reasonable amount of revenues in excess of expenses, which constitutes margins. The margins increase patronage capital, which is the equity component of a cooperative's capitalization. These margins are considered capital contributions (that is, equity) from the members and are held for the accounts of the members and returned to them when the board of directors of the cooperative deems it prudent to do so. The timing and amount of any actual return of capital to the members depends on the financial goals of the cooperative and the cooperative's loan and security agreements.

Power Supply Business

We provide wholesale electric service to our members for a significant portion of their aggregate power requirements primarily from our fleet of generation assets but also with power purchased from other power suppliers. In 2022, we supplied energy that accounted for approximately 58% of the retail energy requirements of our members. We provide this service pursuant to long-term, take-or-pay wholesale power contracts. The wholesale power contracts obligate our members jointly and severally to pay rates sufficient for us to recover all the costs of owning and operating our power supply business, including the payment of principal and interest on our indebtedness and to yield a minimum 1.10 margins for interest ratio under our first mortgage indenture. Our members satisfy all of their power requirements above their purchase obligations to us with purchases from other suppliers. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Our fleet of generating units total 8,477 megawatts of summer planning reserve capacity, which includes 733 megawatts of Smarr EMC assets that we manage but do not own. Our generation portfolio includes units powered by nuclear, gas, coal, oil and water. We also supply financial and management services to support Green Power EMC's purchase of energy from 584 megawatts of renewable resources, including, low-impact hydroelectric, landfill gas, wood-waste biomass and solar facilities. See "– Relationship with Green Power EMC," "OUR POWER SUPPLY RESOURCES," "OUR MEMBERS AND

THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources" – and "PROPERTIES – Generating Facilities."

In 2022, three of our members, Jackson EMC, GreyStone Power Corporation, an EMC, and Cobb EMC, accounted for approximately 16%, 10% and 10% of our total revenues, respectively. Each of our other members accounted for less than 10% of our total revenues in 2022.

Wholesale Power Contracts

The wholesale power contracts we have with each member are substantially similar and extend through December 31, 2050 and continue thereafter until terminated by three years' written notice by us or the respective member. Under the wholesale power contracts, each member is unconditionally obligated, on an express "take-or-pay" basis, for a fixed percentage of the capacity costs of each of our generation resources and purchased power resources with a term greater than one year. Each wholesale power contract specifically provides that the member must make payments whether or not power is delivered and whether or not a resource is completed, delayed, terminated, operable, operating, retired, sold, leased, transferred or is otherwise unavailable. We are obligated to use our reasonable best efforts to operate, maintain and manage our resources in accordance with prudent utility practices.

We have assigned fixed percentage capacity cost responsibilities to our members for all of our generation and purchased power resources, although not all members participate in all resources. For any future resource, we will assign fixed percentage capacity cost responsibilities only to members choosing to participate in that resource. The wholesale power contracts provide that each member is jointly and severally responsible for all costs and expenses of all existing generation and purchased power resources, as well as for future resources, whether or not that member has elected to participate in the resource, that are approved by 75% of the members of our board of directors, 75% of our members and members representing 75% of our patronage capital. In the event a member defaults on all or a portion of its payment obligation, the default amount is shared first among the participating members in each resource in which the defaulting member participates. If all these participating members default, each non-participating member is expressly obligated to pay a proportionate share of the default.

Under the wholesale power contracts, we are not obligated to provide all of our members' capacity and energy requirements. Individual members must satisfy all of their requirements above their purchase obligations from us from other suppliers, unless we and our members agree that we will supply additional capacity and associated energy, subject to the approval requirements described above. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Under the wholesale power contracts, each member must establish rates and conduct its business in a manner that will enable the member to pay (i) to us when due, all amounts payable by the member under its wholesale power contract and (ii) any and all other amounts payable from, or which might constitute a charge or a lien upon, the revenues and receipts derived from the member's electric system, including all operation and maintenance expenses and the principal of, premium, if any, and interest on all indebtedness related to the member's electric system.

New Business Model Member Agreement

The New Business Model Member Agreement that we have with our members requires member approval for us to undertake certain activities. The agreement does not limit our ability to own, manage, control and operate our resources or perform our functions under the wholesale power contracts.

We may not provide services unrelated to our resources or our functions under the wholesale power contracts if these services would require us to incur indebtedness, provide a guarantee or make any loan or investment, unless approved by 75% of the members of our board of directors, 75% of our members, and members representing 75% of our patronage capital. We may provide any other unrelated service to a member so long as (i) doing so would not create a conflict of interest with respect to other members, (ii) the service is being provided to all members or (iii) the service has received the three 75% approvals described above.

Electric Rates

Each member is required to pay us for capacity and energy we furnish under its wholesale power contract in accordance with rates we establish. We review our rates periodically but are required to do so at least once every year. We are required to revise our rates as necessary so that the revenues derived from our rates, together with our revenues from all other sources, will be sufficient to pay all of the costs of our system, including the payment of principal and interest on our indebtedness, to provide for reasonable reserves and to meet all financial requirements.

The formulary rate we established in the rate schedule to the wholesale power contracts employs a rate methodology under which all categories of costs are specifically separated as components of the formula to determine our revenue requirements. The rate schedule also implements the responsibility for fixed costs assigned to each member based on each member's fixed percentage capacity cost responsibilities for all of our generation and purchased power resources. The monthly charges for capacity and other non-energy charges are based on our annual budget. These capacity and other non-energy charges may be adjusted by our board of directors, if necessary, during the year through an adjustment to the annual budget. Energy charges reflect the pass-through of actual energy costs, including fuel costs, variable operations and maintenance costs and purchased energy costs. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Summary of Cooperative Operations – *Rate Regulation.*"

Under the first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates which are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. The formulary rate is intended to provide for the collection of revenues which, together with revenues from all other sources, are equal to all costs and expenses we recorded, plus amounts necessary to achieve at least the minimum 1.10 margins for interest ratio. In the event we were to fall short of the minimum 1.10 margins for interest ratio at year end, the formulary rate is designed to recover the shortfall from our members in the following year without any additional action by our board of directors.

Under our loan agreements with each of the Rural Utilities Service and Department of Energy, changes to our rates resulting from adjustments in our annual budget are generally not subject to their approval. We must provide the Rural Utilities Service and Department of Energy with a notice of and opportunity to object to most changes to the formulary rate under the wholesale power contracts. See "– Relationship with Federal Lenders." Currently, our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

First Mortgage Indenture

Our principal financial requirements are contained in the Indenture, dated as of March 1, 1997, from us to U.S. Bank Trust Company, National Association, as trustee (successor to U.S. Bank National Association), as amended and supplemented, referred to herein as the first mortgage indenture. The first mortgage indenture constitutes a lien on substantially all of our owned tangible and certain of our intangible property, including property we acquire in the future. The mortgaged property includes our owned electric generating plants, the wholesale power contracts with our members and some of our contracts relating to the ownership, operation or maintenance of electric generation facilities owned by us.

Under our first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates which are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. The margins for interest ratio is determined by dividing margins for interest by total interest charges on debt secured under our first mortgage indenture. Margins for interest is the sum of:

- our net margins (after certain defined adjustments), plus
- interest charges on all indebtedness secured under our first mortgage indenture, plus
- any amount included in net margins for accruals for federal or state income taxes.

Margins for interest takes into account any item of net margin, loss, gain or expenditure of any of our affiliates or subsidiaries only if we have received the net margins or gains as a dividend or other distribution from such affiliate or subsidiary or if we have made a payment with respect to the losses or expenditures. In addition, our margins include certain items that are excluded from the margins for interest ratio, such as non-cash capital credits allocation from Georgia Transmission Corporation.

Under our first mortgage indenture, we are prohibited from making any distribution of patronage capital to our members if, at the time of or after giving effect to the distribution, (i) an event of default exists under the first mortgage indenture, (ii) our equity as of the end of the immediately preceding fiscal quarter is less than 20% of our total long-term debt and equities, or (iii) the aggregate amount expended for distributions on or after the date on which our equity first reaches 20% of our total long-term debt and equities exceeds 35% of our aggregate net margins earned after such date. This last restriction, however, will not apply if, after giving effect to such distribution, our equity as of the end of the immediately preceding fiscal quarter is at least 30% of our total long-term debt and equities. As of December 31, 2022, our equity ratio was 9.0%.

As of December 31, 2022, we had approximately $11.9 billion of secured indebtedness outstanding under the first mortgage indenture. From time to time, we may issue additional first mortgage obligations ranking equally and ratably with the existing first mortgage indenture obligations. The aggregate principal amount of obligations that may be issued under the first mortgage indenture is not limited; however, our ability to issue additional obligations under the first mortgage indenture is subject to certain requirements related to the certified value of certain of our tangible property, repayment of obligations outstanding under the first mortgage indenture and payments made under certain pledged contracts relating to property to be acquired.

Relationship with Federal Lenders

Rural Utilities Service

Historically, federal loan programs administered by the Rural Utilities Service, an agency of the United States Department of Agriculture, have provided the principal source of financing for electric cooperatives. Loans guaranteed by the Rural Utilities Service and made by the Federal Financing Bank have been a major source of funding for us. However, Rural Utilities Service loan funds are subject to annual federal budget appropriations, and, due to budgetary and political pressures faced by Congress, the availability and magnitude of these loan funds cannot be assured. The budget for fiscal year 2023, which began October 2022, includes a loan program level of $6.5 billion. We cannot predict the amount or cost of Rural Utilities Service loans that may be available to us in the future.

We have a loan contract with the Rural Utilities Service. Under the loan contract, we may have to obtain approval from the Rural Utilities Service or provide the Rural Utilities Service with a notice and an opportunity to object before we take certain actions, including, without limitation,

- significant additions to or dispositions of system assets,
- significant power purchase and sale contracts,
- changes to the wholesale power contracts and the formulary rate contained in the wholesale power contracts, and
- changes to plant ownership and operating agreements.

As of December 31, 2022, we had $2.8 billion of outstanding loans guaranteed by the Rural Utilities Service and secured under our first mortgage indenture.

Department of Energy

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005, we entered into a loan guarantee agreement with the Department of Energy in 2014, pursuant to which the Department of Energy agreed to guarantee over $3.0 billion of our obligations under a multi-advance term loan facility with the Federal Financing Bank. On March 22, 2019, we and the Department of Energy executed an amended and restated loan guarantee agreement that added $1.6 billion to the loan guarantee. In connection with the increase of the loan guarantee, we entered into additional loan documents with the Federal Financing Bank to increase the aggregate amount available under the term loan facility. Proceeds of advances made under these facilities have been used to reimburse us for over $4.6 billion of costs of construction relating to two additional nuclear units at Plant Vogtle that are eligible for financing under the Title XVII loan guarantee program.

We have advanced all amounts available under the Department of Energy-guaranteed loans. In 2020, we began making principal payments on these loans and, at December 31, 2022, we had $4.3 billion outstanding. All advances received under this facility are secured under our first mortgage indenture.

Under the loan guarantee agreement, we may have to obtain approval from the Department of Energy or provide the Department of Energy with a notice and opportunity to object before we take certain actions, including, without limitation,

- the transfer of our undivided ownership interest in Vogtle Units No. 3 and No. 4 prior to commercial operation of both units,
- significant dispositions of assets pledged under our first mortgage indenture,
- changes to the wholesale power contracts and the formulary rate contained in the wholesale power contracts,
- certain changes to plant ownership and operating agreements relating to Vogtle Units No. 3 and No. 4, and
- agreeing to the removal or replacement of Georgia Power Company or Southern Nuclear Operating Company, Inc. in their respective roles as agents for the Co-owners in connection with the additional Vogtle units.

For additional information regarding the terms of the loan guarantee agreement, see Note 7a of Notes to Consolidated Financial Statements. For additional information on Vogtle Units No. 3 and No. 4, see "– OUR POWER SUPPLY RESOURCES – Future Power Resources – *Vogtle Units No. 3 and No. 4*."

Relationship with Georgia Transmission Corporation

We and our 38 members are members of Georgia Transmission Corporation (An Electric Membership Corporation), which was formed in 1997 to own and operate the transmission business we previously owned. Georgia Transmission provides transmission services to its members for delivery of its members' power purchases from us and other power suppliers. Georgia Transmission also provides transmission services to third parties. We have entered into an agreement with Georgia Transmission to provide transmission services for third party transactions and for service to our own facilities.

Georgia Transmission has rights in the integrated transmission system, which consists of transmission facilities owned by Georgia Transmission, Georgia Power Company, the Municipal Electric Authority of Georgia and the City of Dalton, Georgia. Through agreements, common access to the combined facilities that compose the integrated transmission system enables the owners to use their combined resources to make deliveries to or for their respective consumers, to provide transmission service to third parties and to make off-system purchases and sales. The integrated transmission system was established in order to obtain the benefits of a coordinated development of the parties' transmission facilities and to make it unnecessary for any party to construct duplicative facilities.

Relationship with Georgia System Operations Corporation

We, Georgia Transmission and our 38 members are members of Georgia System Operations Corporation, which was formed in 1997 to own and operate the system operations business we previously owned. Georgia System Operations operates the system control center and currently provides Georgia Transmission and us with system operations services and administrative support services. We have contracted with Georgia System Operations to schedule and dispatch our resources. We also purchase from Georgia System Operations services that it purchases from Georgia Power under the Control Area Compact, which we co-signed with Georgia System Operations. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Members' Relationship with Georgia Transmission and Georgia System Operations." Georgia System Operations provides support services to us in the areas of accounts payable, payroll, auditing, human resources, campus services, telecommunications and information technology at cost.

We have made loans to Georgia System Operations primarily for the purpose of financing its capital expenditures. As of December 31, 2022, the balance of the loans outstanding was $11.5 million. Georgia System Operations has an additional $7.0 million that it can draw under one of its loans with us.

Georgia Transmission has contracted with Georgia System Operations to provide certain transmission system operation services including reliability monitoring, switching operations, and the real-time management of the transmission system.

Relationship with Georgia Power Company

Our relationship with Georgia Power is a significant factor in several aspects of our business. Except for the Rocky Mountain Pumped Storage Hydroelectric Facility, Georgia Power, on behalf of itself as a co-owner and as agent for the other co-owners, is responsible for the construction and operation of all our co-owned generating facilities, including the construction of Vogtle Units No. 3 and No. 4. For further information regarding the agreements between Georgia Power and us, see "PROPERTIES – Fuel Supply," "– Co-Owners of Plants – *Georgia Power Company*" and "– The Plant Agreements." Georgia Power supplies services to us and Georgia System Operations to support the scheduling and dispatch of our resources, including off-system transactions. Georgia Power and our members are competitors in the State of Georgia for electric service to any new customer that has a choice of supplier under the Georgia Territorial Electric Service Act, which was enacted in 1973, commonly known as the Georgia Territorial Act (see "– Competition"). For further information regarding our members' relationships with Georgia Power, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Service Area and Competition."

Relationship with Smarr EMC

Smarr EMC is a Georgia electric membership corporation owned by 35 of our 38 members. Smarr EMC owns two combustion turbine facilities with aggregate summer planning reserve capacity of 733 megawatts. We provide operations, financial and management services to Smarr EMC. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Relationship with Green Power EMC

Green Power Electric Membership Corporation, owned by our 38 members, is a power supply cooperative specializing in the purchase of renewable energy for its members. Green Power EMC currently manages 584 megawatts of renewable energy resources. By 2025, the capacity is expected to increase by at least 252 megawatts, bringing the total capacity to more than 836 megawatts. We supply financial and management services to Green Power EMC. For more information on the renewable resources of Green Power EMC, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Green Power EMC*."

Competition

Under current Georgia law, our members generally have the exclusive right to provide retail electric service in their respective territories. However, the Georgia Territorial Act permits limited competition among electric utilities located in Georgia for sales of electricity to certain large commercial or industrial customers. The owner of any new facility may receive electric service from the power supplier of its choice if the facility is located outside of municipal limits and has a connected load upon initial full operation of 900 kilowatts or more. Our members are actively engaged in competition with other retail electric suppliers for these new commercial and industrial loads. This limited competition has given our members the opportunity to develop resources and strategies to operate in a more competitive market.

Some states have implemented varying forms of retail competition among power suppliers. No legislation related to retail competition has yet been enacted in Georgia which would amend the Georgia Territorial Act or otherwise affect the exclusive right of our members to supply power to their current service territories. However, parties have unsuccessfully sought and will likely continue to seek to advance legislative proposals that will directly or indirectly affect the Georgia Territorial Act in order to allow increased retail competition in our members' service territories. The Georgia Public Service Commission does not have the authority under Georgia law to order retail competition or amend the Georgia Territorial Act.

We routinely consider, along with our members, a wide array of potential actions to meet future power supply needs, maintain competitive rates, adapt to technological innovations, including distributed generation and energy storage technologies, and respond to the evolving competitive and regulatory landscape. We cannot predict at this time the outcome of various developments that may lead to increased competition in the electric utility industry or the effect of any developments on us or our members.

Regulation of greenhouse gas emissions has the potential to affect energy suppliers, including us and our competitors, differently, depending on the relative greenhouse gas emissions from a supplier's sources and the nature of the regulation. Some of our generation sources emit greenhouse gases while others emit none. Comparatively, our competitors may rely on sources that emit proportionately more or less greenhouse gases than we do. Further, many of our members' third-party suppliers also rely on generation sources that emit greenhouse gases. The terms and conditions in the contracts with these third-party suppliers would determine the extent to which any greenhouse gas regulation of these suppliers affects our members. We believe our and our members' diverse portfolios of generation facilities, including the diversity of third-party suppliers, would mitigate impacts on our and our members' competitiveness resulting from any regulation. See "REGULATION – Environmental – *Carbon Dioxide Emissions and Climate Change*" and "RISK FACTORS."

Many members are also providing or considering proposals to provide non-traditional products and services such as natural gas, telecommunications (including broadband) and other services. The Georgia Public Service Commission can authorize member affiliates to market natural gas but is required to condition any authorization on terms designed to ensure that cross-subsidizations do not occur between the electricity services of a member and the gas activities of its gas affiliates. Among other conditions, for members providing broadband services through an affiliate, the Georgia Public Service Commission must approve a cost allocation manual designed to ensure that cross-subsidizations do not occur between the broadband services and the electric and/or gas services of a member or its affiliates.

Further, a member's power supply planning may include consideration of assignment of its rights and obligations under its wholesale power contract to another member or a third party. We have existing provisions for wholesale power contract assignment, as well as provisions for a member to withdraw and concurrently to assign its rights and obligations under its wholesale power contract. Assignments upon withdrawal require the assignee to have certain published credit ratings and to assume all of the withdrawing member's obligations under its wholesale power contract with us, and must be approved by our board of directors. Assignments without withdrawal are governed by the wholesale power contract and must be approved by both our board of directors and the Rural Utilities Service.

From time to time, individual members may be approached by parties indicating an interest in purchasing their systems. A member generally must obtain our approval before it may consolidate or merge with any person or reorganize or change the form of its business organization from an electric membership corporation or sell, transfer, lease or otherwise dispose of all or substantially all of its assets to any person, whether in a single transaction or series of transactions. A member may enter into such a transaction without our approval if specified conditions are satisfied, including, but not limited to, an agreement by the transferee, satisfactory to us, to assume the obligations of the member under the wholesale power contract, and certifications of accountants as to certain specified financial requirements of the transferee. The wholesale power contracts also provide that a member may not dissolve, liquidate or otherwise wind up its affairs without our approval.

Seasonal Variations

Our members' demand for energy is influenced by seasonal weather conditions. Historically, higher demand has occurred during summer and winter months than in spring and fall months. Even so, summer and winter demand historically has been lower when weather conditions are milder and higher when weather conditions are more extreme. A variety of factors affect our members' decisions whether to purchase their increased seasonal demand from us. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION – Results of Operations – *Factors Affecting Results*." While changing weather patterns, whether resulting from greenhouse gas emissions or otherwise, could, under certain circumstances, alter seasonal weather patterns, predictions of future changes in weather patterns are inherently speculative, and we cannot make accurate conclusions about seasonality related to changes in weather patterns. Our energy revenues recover energy costs as they are incurred and also fluctuate month to month. Capacity revenues are based upon budgeted expenditures and are generally recognized and billed to our members in substantially equal monthly installments over the course of the year. We may recognize capacity revenues that exceed our actual fixed costs and targeted margins in any given interim reporting period. At each interim reporting period, we assess our projected revenue requirements through year end and if required, we reduce our capacity revenues and recognize a refund liability to our members. See Note 1e of Notes to Consolidated Financial Statements for information regarding revenue recognition.

Human Capital

Our success depends on the people who are part of our company. We believe that in order to deliver superior performance and maximize the value of our members’ investment, we must attract and retain the most qualified workforce available. We further believe that a strong corporation requires initiative, commitment and talent from its employees and that exceptional results evolve from diversity, continuous improvement, personal development and the contributions of many working toward common goals. We are focused on fostering innovation and leadership with our associates. We also place a strong emphasis on training because we know this ultimately leads to our associates' professional success and the success of our company.

As of December 31, 2022, we had 323 employees. Substantially all of our associates are full-time employees and are located in Georgia. We have a formal Code of Conduct that, among other things, requires that we treat each other, and those outside our company with whom we do business, professionally and with fairness and respect. We must also conduct ourselves in a manner that promotes a favorable image of our company and a positive and professional workplace environment that promotes harmonious relationships among each other and our members.

We strive to provide fair and equitable compensation to each of our associates through a combination of competitive base pay, performance incentives, retirement plans and other benefits. The philosophy and objective of our compensation and benefits program is to establish and maintain competitive total compensation programs that will attract, motivate and retain the qualified skilled workforce necessary for our continued success. We set uniform performance goals at the corporate level. Those goals are the same for both executive officers and non-executive associates as achieving these performance incentives requires the effort and attention of associates across our business, see "EXECUTIVE COMPENSATION – Compensation Discussion and Analysis – *Corporate Goals for Performance Pay*."

We are also committed to continuing efforts to enhance diversity, inclusion and equity. We are dedicated to creating and maintaining an environment that respects and values diversity, recognizes the rights of all individuals to mutual respect, and accepts others without biases based on differences of any kind.

Safety is a key concern of our management team. As an electric generation utility, we are committed to providing a safe work environment for all our associates. Our corporate goals, which are reflected in the performance pay component of total compensation, reflect a commitment to provide comprehensive safety training and education and continue to find new ways to reduce workplace hazards.

As an electric cooperative, we are also committed to being a positive influence in the communities we serve. To accomplish this goal, we support and encourage our associates to participate in a variety of initiatives and activities that help the communities where we and our members live and work.

OUR POWER SUPPLY RESOURCES

General

We supply capacity and energy to our members for a portion of their requirements from a combination of our fleet of generating assets and power purchased from other suppliers. In 2022, we supplied approximately 58% of the retail energy requirements of our members. Our members purchased the remaining 42% from a variety of suppliers, including Green Power EMC (renewable resources), Smarr EMC (gas-fired resources), Georgia Energy Cooperative (gas-fired resource), Southeastern Power Administration (hydroelectric power), and several power marketers and other wholesale suppliers. For more detailed information on these other purchases, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Generating Plants

Our fleet of generating units total 8,477 megawatts of summer planning reserve capacity, including 733 megawatts of Smarr EMC assets, which we manage. Our generation portfolio includes interests in nuclear, coal, natural gas, oil and hydro units. Georgia Power, the Municipal Electric Authority of Georgia (MEAG) and the City of Dalton also have interests in six of these units at Plants Hatch, Vogtle and Scherer. Georgia Power serves as operating agent for these six units. Georgia Power also has an interest in the three units at Rocky Mountain, which we operate. In addition to our 31 generating units, we operate and manage six gas-fired generating units on behalf of Smarr EMC.

See "PROPERTIES" for a description of our generating facilities, fuel supply and the co-ownership arrangements. For a description of Smarr EMC's assets, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Smarr EMC."*

Power Purchase and Sale Arrangements

We currently have no material power purchase or sale agreements.

We supply financial and management services to support Green Power EMC's purchase of energy from 584 megawatts of renewable resources, plus an additional 252 megawatts under contract to be constructed. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Green Power EMC*."

We have interchange, transmission and/or short-term capacity and energy purchase or sale agreements with a number of power marketers and other power suppliers. The agreements provide variously for the purchase and/or sale of capacity and energy and/or for the purchase of transmission service.

We are a member of the Southeast Energy Exchange Market (SEEM) which began successfully operating in November 2022. SEEM, whose members include the traditional electric operating companies and many of the other electric service providers in the Southeast, is an extension of the existing bilateral market in which participants use an automated, intra-hour energy exchange to buy and sell power near the time the energy is consumed, utilizing available unreserved transmission. Our participation in SEEM has had minimal impact on our business to date. The FERC's orders related to SEEM have been appealed. The ultimate outcome of this matter cannot be determined at this time.

Future Power Resources

Plant Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units under construction at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company, Inc. as its agent for licensing, engineering, procurement, contract management, construction and pre-operation services.

In 2008, Georgia Power, acting for itself and as agent for the Co-owners, entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with Westinghouse Electric Company LLC and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (collectively, Westinghouse). Pursuant to the EPC Agreement, Westinghouse agreed to design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle.

Until March 2017, construction on Units No. 3 and No. 4 continued under the substantially fixed price EPC Agreement. In March 2017, Westinghouse filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Effective in July 2017, Georgia Power, acting for itself and as agent for the other Co-owners, and Westinghouse entered into a services agreement (the Services Agreement), pursuant to which Westinghouse is providing facility design and engineering services, procurement and technical support and staff augmentation on a time and materials cost basis. The Services Agreement provides that it will continue until the start-up and testing of Vogtle Units No. 3 and No. 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Co-owners upon 30 days' written notice.

In October 2017, Georgia Power, acting for itself and as agent for the other Co-owners, entered into a construction completion agreement with Bechtel Power Corporation, pursuant to which Bechtel serves as the primary contractor for the remaining construction activities for Vogtle Units No. 3 and No. 4 (the Bechtel Agreement) and is reimbursed for actual costs plus a base fee and an at-risk fee, subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Co-owner is severally, and not jointly, liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Co-owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Co-owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Co-owner suspensions of work, certain breaches of the Bechtel Agreement by the Co-owners, Co-owner insolvency and certain other events.

Cost and Schedule

Our current budget for our ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs, allowance for funds used during construction and some level of contingency is $8.1 billion and is based on commercial operation dates of June 2023 and March 2024 for Units No. 3 and No. 4, respectively. This budget reflects our June 17, 2022 exercise of the tender option in the Global Amendments to the Joint Ownership Agreements as described below. Had we not exercised the tender option, our budget would be approximately $8.65 billion. At December 31, 2022, our total investment for our interest in the additional Vogtle units was approximately $8.0 billion. We and some of our members have implemented various rate management programs to lessen the impact on rates when Vogtle Units No. 3 and No. 4 reach commercial operation.

Our initial ownership interest and proportionate share of the cost to construct the additional Vogtle units was 30%, representing approximately 660 megawatts. However, we have exercised the tender option discussed below which caps our capital costs in exchange for a proportionate reduction of our 30% interest in the two units. Based on the current project budget and schedule and our interpretation of the Global Amendments (described below), we would transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share would decline from 30% to approximately 27.5%. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced.

The table below shows our project budget and actual costs through December 31, 2022 for our share of the project.

	(in millions)	
	Project Budget (Tender)	Actual Costs at December 31, 2022
Construction Costs [1]	$ 6,554	$ 6,147
Freeze Capital Credit [2]	(528)	—
Financing Costs	2,025	1,770
Subtotal	$ 8,051	$ 7,917
Deferred Training Costs	47	46
Total Project Costs Before Contingency	$ 8,098	$ 7,963
Oglethorpe Contingency	$ 2	$ —
Totals	$ 8,100	$ 7,963

[1] Construction costs are net of $1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and $99 million in cost sharing benefits associated with the Global Amendments to the Joint Ownership Agreement.

[2] As described below, we exercised the tender option to cap our capital costs at the EAC in VCM 19 plus $2.1 billion, the freeze tender threshold. The freeze capital credit reflects our share of budgeted amounts that exceed this threshold.

Oglethorpe-level contingency, which we have carried at various levels since the beginning of the project, provides additional margin to cover potential cost, schedule, and financing risks associated with our share of the project. At the end of the project, if there is remaining Oglethorpe-level contingency, we will adjust our project budget to remove this contingency and bill our members based on the actual project costs. Any schedule extension beyond June 2023 and March 2024 for Units No. 3 and No. 4, respectively, is expected to increase our financing costs by approximately $30 million per month for both units and approximately $13 million per month for Unit No. 4.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts on a regular basis to incorporate current information available, particularly in the areas of start-up testing and related test results, engineering support, commodity installation, system turnovers and workforce statistics.

Since March 2020, the number of active cases of COVID-19 at the site has fluctuated consistent with the surrounding area and impacted productivity levels and pace of activity completion. As of December 31, 2022, the incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity, substantially all of which occurred during 2020 and 2021, is estimated by Georgia Power to be between $350 million and $438 million and is included in the project budget. Future COVID-19 variants could further disrupt or delay construction, testing, supervisory, and support activities at Vogtle Units No. 3 and No. 4.

On July 29, 2022, Southern Nuclear announced that all Unit No. 3 inspections, tests, analyses, and acceptance criteria documentation had been submitted to the Nuclear Regulatory Commission. On August 3, 2022, the Nuclear Regulatory Commission published its 103(g) finding that the acceptance criteria in the combined license for Unit No. 3 had been met, which allowed for nuclear fuel to be loaded and start-up testing to begin. Fuel load for Unit No. 3 was completed on October 17, 2022. In early 2023, during the start-up and pre-operational testing for Unit No. 3, Southern Nuclear identified and remediated certain equipment and component issues. On March 6, 2023, the Unit No. 3 nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality, a key milestone in the start-up process. Georgia Power has disclosed that it projects an in-service date for Unit No. 3 during May or June of 2023. Our current budget reflects our expectation of an in-service date for Unit No. 3 in June 2023. The projected schedule for Unit No. 3 primarily depends on the progression of final component and pre-operational testing and start-up, which may be impacted by further equipment, component and/or other operational challenges.

Georgia Power has disclosed that it projects an in-service date for Unit No. 4 during late fourth quarter 2023 or during the first quarter 2024. Given the remaining work to be done and potential risks associated with completing the work, our current budget anticipates an in-service date for Unit No. 4 in March 2024. Meeting the projected in-service date for Unit No. 4 primarily depends on potential impacts arising from Unit No. 4 testing activities overlapping with Unit No. 3 start-up and commissioning; maintaining overall construction productivity and production levels improving, particularly in subcontractor scopes of work; and maintaining appropriate levels of craft laborers. As Unit No. 4 completes construction and transitions further into testing, ongoing and potential future challenges include the duration of hot functional testing, which commenced on March 20, 2023, and other testing, the pace and quality of remaining commodities installation; completion of documentation to support inspections, tests, analyses and acceptance criteria submittals; the pace of remaining work package closures and system turnovers; and availability of craft, supervisory and technical support resources.

Ongoing or future challenges for both units also include management of contractors and vendors; subcontractor performance; and/or related cost escalation. New challenges also may continue to arise, as Unit No. 3 completes start-up and commissioning and Unit No. 4 moves further into testing and startup, which may result in required engineering changes or remediation related to plant systems, structures or components (some of which are based on new technology that only within the last few years began initial operation in the global nuclear industry at this scale). These challenges may result in further schedule delays and/or cost increases.

There have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to ensure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction.

With the receipt of the Nuclear Regulatory Commission’s 103(g) finding, Unit No. 3 is now under the Nuclear Regulatory Commission’s operating reactor oversight process and must meet applicable technical and operational requirements contained within its operating license. Various design and other licensing-based compliance matters, including the timely submittal by Southern Nuclear of the inspections, tests, analyses, and acceptance criteria documentation and the related reviews and approvals by the Nuclear Regulatory Commission necessary to support authorization to load fuel for Unit No. 4, may arise, which may result in additional license amendment requests or require other resolution. If any license amendment requests or other licensing-based compliance issues, including inspections, tests, analyses, and acceptance criteria for Unit No. 4, are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

The ultimate outcome of these matters cannot be determined at this time.

Co-Owner Contracts and Other Information

In November 2017, the Co-owners entered into an amendment to their joint ownership agreements for Vogtle Units No. 3 and No. 4 to provide for, among other conditions, additional Co-owner approval requirements. These joint ownership agreements, including the Co-owner approval requirements, were subsequently amended, effective August 31, 2018. As described below, certain provisions of the Joint Ownership Agreements were modified further on September 26, 2018 by the Term Sheet that was memorialized on February 18, 2019 when the Co-owners entered into certain amendments (the Global Amendments) to the Joint Ownership Agreements (as amended, the Joint Ownership Agreements).

As a result of an increase in the total project capital cost forecast and Georgia Power’s decision not to seek recovery of its allocation of the increase in the base capital costs and the increased construction budget in connection with Georgia Power’s nineteenth Vogtle construction monitoring report (VCM 19) in 2018, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 were required to vote to continue construction. In September 2018, the Co-owners unanimously voted to continue construction of Vogtle Units No. 3 and No. 4.

In connection with the September 2018 vote to continue construction, Georgia Power entered into a binding term sheet with the other Co-owners and MEAG’s wholly-owned subsidiaries MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, and MEAG Power SPVP, LLC to mitigate certain financial exposure for the other Co-owners and offered to purchase production tax credits from each of the other Co-Owners, at that Co-owner’s option (the Term Sheet). On February 18, 2019, the Co-owners entered into the Global Amendments to memorialize the provisions of the Term Sheet. Pursuant to the Global Amendments and consistent with the Term Sheet, the Joint Ownership Agreements provide that:

- each Co-owner is obligated to pay its proportionate share of construction costs for Vogtle Units No. 3 and No. 4 based on its ownership interest up to (i) the estimated cost at completion ("EAC") for Vogtle Units No. 3 and No. 4 which formed the basis of Georgia Power's forecast of $8.4 billion in Georgia Power's VCM 19 filed with the Georgia Public Service Commission plus (ii) $800 million of additional construction costs.

- Georgia Power will be responsible for 55.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $800 million to $1.6 billion (resulting in up to

$80 million of potential additional costs to Georgia Power which would save Oglethorpe up to $44 million), with the remaining Co-owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests (equal to 24.5% for our 30% ownership interest); and

- Georgia Power will be responsible for 65.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $1.6 billion to $2.1 billion (resulting in up to a further $100 million of potential additional costs to Georgia Power which would save Oglethorpe up to an additional $55 million), with the remaining Co-owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests (equal to 19.0% for our 30% ownership interest).

If the EAC is revised and exceeds the EAC in VCM 19 by more than $2.1 billion, each of the Co-owners, other than Georgia Power, has a one-time option to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Co-owner's share of construction costs actually incurred in excess of the EAC in VCM 19 plus $2.1 billion. If any Co-owner elects to exercise this tender option, Georgia Power would have the option to cancel the project in lieu of accepting the offer to purchase a portion of the Co-owner's ownership interest. If Georgia Power does not elect to cancel the project, then Georgia Power must accept the offer, and the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the percentage of the cumulative amount of construction costs paid by such tendering Co-owner as of the commercial operation date of Vogtle Unit No. 4. For purposes of this calculation, payments made by Georgia Power on behalf of the tendering Co-owner in accordance with the second and third bullets above will be treated as payments made by that Co-owner. This option to tender a portion of our interest to Georgia Power upon such a budget increase would allow us to freeze our construction budget associated with the Vogtle project in exchange for a proportionate reduction of our 30% ownership interest.

The VCM 19 total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. As of December 31, 2021, budget increases since VCM 19 reached $3.4 billion for all Co-owners. As a result of those increases, we believe that the tender option was triggered at the Co-owner construction budget vote on February 14, 2022 and that Georgia Power's increased responsibility for certain construction costs as described above commenced in March 2022.

On June 17, 2022, we notified Georgia Power of our election to exercise the tender option and cap our capital costs in exchange for a proportionate reduction of our 30% interest in the two new units. Our decremental ownership interest will be calculated and conveyed to Georgia Power after both Vogtle units are placed in service. Based on the current project budget, our schedule assumptions and our interpretation of the Global Amendments, our project budget is $8.1 billion and we expect to transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share will decline from 30% to approximately 27.5%. By exercising the tender option and based on current assumptions, we estimate that we will avoid incurring approximately $530 million in construction costs associated with the project. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced. On July 26, 2022, the City of Dalton notified Georgia Power that it had elected to exercise its tender option.

We and Georgia Power do not agree on certain aspects of the tender option, including the dollar amount that triggers our option to tender a portion of our ownership interest to Georgia Power under the tender option or the extent to which costs that are the result of a force majeure event (such as COVID-19) impact the point at which the tender option is triggered. For purposes of determining when our option to tender has been triggered, the Global Amendments do not exclude costs resulting from force majeure events (such as COVID-19) from the calculation of when the EAC in VCM 19 plus $2.1 billion has been reached. We and Georgia Power also do not agree on the dollar amount that triggers Georgia Power's increased responsibility for certain construction costs as described above, and the extent to which costs that are the result of a force majeure event (such as COVID-19), impact the calculation of the point at which Georgia Power's increased responsibility for certain construction costs as described above is triggered. The exclusion of costs resulting from a force majeure event (such as COVID-19) in the Global Amendments only applies to Georgia Power's increased cost responsibility during the time period when construction costs exceed the EAC in VCM 19 by $800 million to $2.1 billion.

Accordingly, in March 2022, we notified Georgia Power of a billing dispute with regards to both the starting dollar amount and the application of costs resulting from a force majeure event and how such amounts impact the thresholds and timing of the cost-sharing and tender option provisions. On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County, Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim against us seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power's related financial obligations. Based on the current project budget and Georgia Power's interpretation of the Global Amendments, our project budget would be $8.65 billion, and we would incur approximately $530 million of additional construction costs (excluding related financing costs) and retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

Pursuant to the Joint Ownership Agreements, as amended by the Global Amendments, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Global Amendment provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more from the seventeenth VCM report estimated in-service dates of November 2021 and November 2022 for Units No. 3 and No. 4, respectively (each a Project Adverse Event). The schedule extensions, announced in February 2022, which reflected a cumulative delay of over a year for each unit from the schedules approved in the seventeenth VCM report, triggered the requirement for the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 to vote to continue construction, and the Co-owners unanimously voted to continue construction.

The Global Amendments provide that Georgia Power may cancel the project at any time at its sole discretion. In the event that Georgia Power determines to cancel the project or fewer than 90% of the Co-owners vote to continue construction upon the occurrence of a subsequent project adverse event, we and the other Co-owners would assess our options for the Vogtle project. If the investment were to be written off, we would seek regulatory accounting treatment to amortize the investment over a long-term period, which requires the approval of our board of directors, and we would submit the regulatory accounting treatment details to the Rural Utilities Service for its approval. Further, if Georgia Power or the Co-owners decided to cancel the project, the Department of Energy would have the discretion to require that we repay all amounts outstanding under our loan guarantee agreement with the Department of Energy over a five-year period as discussed in Note 7a of Notes to Consolidated Financial Statements.

The ultimate outcome of these matters cannot be determined at this time.

Financing

We have loans from the Federal Financing Bank guaranteed by the Department of Energy to fund a portion of the cost to construct Vogtle Units No. 3 and No. 4. In December 2022, we made the last advance under these loans and completed borrowings of over $4.6 billion under these guaranteed loans, which began amortizing in 2020. For additional information regarding terms of the loan and loan guarantee agreement with the Department of Energy, including potential repayment over a five-year period, covenants and events of default, see Note 7a of Notes to Consolidated Financial Statements.

As of December 31, 2022, we had financed $2.8 billion of the capital costs of the Vogtle units through capital market debt issuances. We anticipate financing the remaining costs of the Vogtle units and amounts amortized under the Department of Energy-guaranteed loan in the capital markets. For additional information regarding the financing of Vogtle Units No. 3 and No. 4, see "MANAGEMENT'S DISCUSSION OF AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—Financing Activities—Department of Energy-Guaranteed Loans."

Under the Bipartisan Budget Act of 2018, we qualify for nuclear production tax credits related to Vogtle Units No. 3 and No. 4. We expect to receive these tax credits in accordance with our ownership interest in the Vogtle Units. We estimate that the nominal value of our allocation of production tax credits will be up to $650 million and will be earned for eight years post commercial operation. Our estimate of the total value of our tax credits reflects the proportionate reduction of our ownership share of the Vogtle Units as a result of exercising the tender option. Pursuant to the Global Amendments, Georgia Power agreed to purchase our allocation of production tax credits at varying purchase prices dependent upon the actual cost to complete construction of Vogtle Units No. 3 and No. 4 as compared to the EAC in VCM 19. Based on the current project budget, the purchase price would be 98% of face value. Any purchases will be at our option and would occur after such production tax credits are earned. We will continue to analyze various options to monetize these credits with one or more third parties, including Georgia Power. In order to maximize the value of these production tax credits, we do not anticipate entering into any agreement to sell these production tax credits until one or both of the Vogtle Units reach commercial operation. We expect to use the proceeds received from the sale of production tax credits to offset operating costs following commercial operation of the Vogtle Units. Any amounts received from these sales will not affect our project budget.

The ultimate outcome of these matters cannot be determined at this time.

See “RISK FACTORS” for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units.

Washington County Power Facility

On December 20, 2022, we acquired two generating units at the Washington County Power Plant, a four-unit 660 megawatt combustion turbine generation and transmission facility located in Sandersville, Georgia, from Gulf Pacific Power, LLC, an investment fund managed by Harbert Management Corporation. The two acquired units added over 300 megawatts of natural gas-fired capacity to our generation portfolio. As part of the acquisition of the units, we assumed an existing power purchase and sale agreement to sell the capacity and associated energy to Georgia Power through May 31, 2024. On June 1, 2024, the output of the acquired units will be available to our subscribing members.

Other Future Power Resources

From time to time, we may assist our members in investigating potential new power supply resources, after compliance with the terms of the New Business Model Member Agreement. See "OGLETHORPE POWER CORPORATION – New Business Model Member Agreement." Following passage of the Inflation Reduction Act in 2022, we and our members are evaluating new incentives available to us to further diversify our generation portfolio through the addition of new battery storage and renewable generation resources.

OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES

Member Demand and Energy Requirements

Our members are listed below and include 38 of the 41 electric distribution cooperatives in the State of Georgia.

Altamaha EMC
Amicalola EMC
Canoochee EMC
Carroll EMC
Central Georgia EMC
Coastal EMC (d/b/a Coastal Electric Cooperative)
Cobb EMC
Colquitt EMC
Coweta Fayette EMC
Diverse Power Incorporated, an EMC
Excelsior EMC
Flint EMC (d/b/a Flint Energies)
Grady EMC
GreyStone Power Corporation, an EMC
Habersham EMC
Hart EMC
Irwin EMC
Jackson EMC
Jefferson Energy Cooperative, an EMC
Little Ocmulgee EMC
Middle Georgia EMC
Mitchell EMC
Ocmulgee EMC
Oconee EMC
Okefenoke Rural EMC
Planters EMC
Rayle EMC
Satilla Rural EMC
Sawnee EMC
Slash Pine EMC
Snapping Shoals EMC
Southern Rivers Energy, Inc., an EMC
Sumter EMC
Three Notch EMC
Tri-County EMC
Upson EMC
Walton EMC
Washington EMC

Our members serve approximately 2.1 million electric consumers (meters) representing approximately 4.4 million people. Our members serve a region covering approximately 38,000 square miles, which is approximately 65% of the land area in the State of Georgia, encompassing 151 of the State's 159 counties. Historically, our members' sales by customer class have been approximately two-thirds to residential consumers and slightly less than one-third to commercial and industrial consumers. Our members are the principal suppliers for the power needs of rural Georgia. While our members do not serve any major cities, portions of their service territories are in close proximity to urban areas and have experienced substantial growth over the years due to the expansion of urban areas, including metropolitan Atlanta, into suburban areas and the growth of suburban areas into neighboring rural areas. Each year we file an exhibit containing financial and statistical information for our 38 members for the most recent three year period with our first quarter Form 10-Q.

The following table shows the aggregate peak demand and energy requirements of our members for the years 2020 through 2022, and also shows the amount of their energy requirements that we supplied. From 2020 through 2022, peak demand of the members and their energy requirements have fluctuated based on various factors. Our member system hit a new peak demand twice in 2022. In December 2022, our member system hit a new peak demand of 10,810(4) megawatts, eclipsing our members' prior peak of 10,018 megawatts achieved in June 2022. We estimate that the overall impact of COVID-19 on our members' energy requirements to be a decrease of approximately one percent in 2020 and no effect for 2021 or 2022.

		Member Energy Requirements (MWh)	
	Member Peak Demand (MW)(1)	Total(2)	Supplied by Oglethorpe(3)
2022	10,810(4)	42,175,373	25,634,984
2021	9,284	39,701,458	24,727,600
2020	9,471	39,208,224	22,187,311

(1) System peak hour demand of our members measured at our members' delivery points (net of system losses), adjusted to include requirements served by us and member resources, to the extent known by us, behind the delivery points. Also includes energy we supplied to our own facilities.

(2) Retail requirements served by our and member resources, adjusted to include requirements served by resources, to the extent known by us, behind the delivery points. See "– Member Power Supply Resources." Also includes energy we supplied to our own facilities.

(3) Includes energy supplied to members for resale at wholesale. Also includes energy we supplied to our own facilities.

(4) System peak hour demand measured at our generating resources was 11,077 megawatts and system peak hour demand measured at our members' delivery points was 10,810 megawatts.

Service Area and Competition

The Georgia Territorial Act regulates the service rights of all retail electric suppliers in the State of Georgia. Pursuant to the Georgia Territorial Act, the Georgia Public Service Commission assigned substantially all areas in the State to specified retail suppliers. With limited exceptions, our members have the exclusive right to provide retail electric service in their respective territories, which are predominately outside of the municipal limits existing at the time the Georgia Territorial Act was enacted in 1973. The principal exception to this rule of exclusivity is that electric suppliers may compete for most new retail loads of 900 kilowatts or greater. Parties have unsuccessfully sought and will likely continue to seek to advance legislative proposals that will directly or indirectly affect the Georgia Territorial Act in order to allow increased retail competition in our members' service territories.

The Georgia Public Service Commission may reassign territory only if it determines that an electric supplier has breached the tenets of public convenience and necessity. The Georgia Public Service Commission may transfer service for specific premises only if: (i) it determines, after joint application of electric suppliers and proper notice and hearing, that the public convenience and necessity require a transfer of service from one electric supplier to another; or (ii) it finds, after proper notice and hearing, that an electric supplier's service to the premises is not adequate or dependable or that its rates, charges, service rules and regulations unreasonably discriminate in favor of or against the consumer utilizing the premises and the electric utility is unwilling or unable to comply with an order from the Georgia Public Service Commission regarding the service.

The Georgia Territorial Act allows limited competition among electric utilities in Georgia by allowing the owner of any new facility located outside of municipal limits and having a connected load upon initial full operation of 900 kilowatts or greater to receive electric service from the retail supplier of its choice. Our members, with our support, are actively engaged in competition with other retail electric suppliers for these new commercial and industrial loads. The number of commercial and industrial loads served by our members continues to increase annually. This limited competition has given our members and us the opportunity to develop resources and strategies to operate in an increasingly competitive market.

For further information regarding members' competitive activities, see "OGLETHORPE POWER CORPORATION – Competition."

Cooperative Structure

Our members are cooperatives that operate their systems on a not-for-profit basis. Accumulated margins derived after payment of operating expenses and provision for depreciation constitute patronage capital of the consumers of our members. Refunds of accumulated patronage capital to the individual consumers may be made from time to time subject to limitations contained in mortgages between the members and the Rural Utilities Service or loan documents with other lenders. The Rural Utilities Service mortgages generally prohibit these distributions unless (i) after any of these distributions, the member's total equity will equal at least 30% of its total assets or (ii) distributions do not exceed 25% of the margins and patronage capital received by the member in the preceding year and equity is at least 20% of total assets. See "– Members' Relationship with the Rural Utilities Service."

We are a membership corporation, and our members are not our subsidiaries. Except with respect to the obligations of our members under each member's wholesale power contract with us and our rights under these contracts to receive payment for power and energy supplied, we have no legal interest in (including through a pledge or otherwise), or obligations in respect of, any of the assets, liabilities, equity, revenues or margins of our members. See "OGLETHORPE POWER CORPORATION – Wholesale Power Contracts." The assets and revenues of our members are, however, pledged under their respective mortgages with the Rural Utilities Service or loan documents with other lenders.

We depend on the revenue we receive from our members pursuant to the wholesale power contracts to cover the costs of operation of our power supply business and satisfy our debt service obligations.

Rate Regulation of Members

Through provisions in the loan documents securing loans to the members, the Rural Utilities Service exercises control and supervision over the rates for the sale of power of our members that borrow from it. The Rural Utilities Service mortgage indentures of these members require them to design rates with a view to maintaining an average times interest earned ratio and an average debt service coverage ratio of not less than 1.25 and an operating times interest earned ratio and an operating debt service coverage ratio of not less than 1.10, in each case for the two highest out of every three successive years.

The Georgia Electric Membership Corporation Act, under which each of the members was formed, requires the members to operate on a not-for-profit basis and to set rates at levels that are sufficient to recover their costs and to provide for reasonable reserves. The setting of rates by the members is not subject to approval by any federal or state agency or authority other than the Rural Utilities Service, but the Georgia Territorial Act prohibits the members from unreasonable discrimination in the setting of rates, charges, service rules or regulations and requires the members to obtain Georgia Public Service Commission approval of long-term borrowings.

Cobb EMC, Diverse Power Incorporated, an EMC, Mitchell EMC, Oconee EMC, Okefenoke Rural EMC, Snapping Shoals EMC and Walton EMC have repaid all of their Rural Utilities Service indebtedness and are no longer Rural Utilities Service borrowers. Each of these members now has a rate covenant with its current lender. Other members may also pursue this option. To the extent a member that is not a Rural Utilities Service borrower engages in wholesale sales or sales of transmission service in interstate commerce, it would, in certain circumstances, be subject to regulation by the Federal Energy Regulatory Commission under the Federal Power Act.

Members' Relationship with the Rural Utilities Service

Through provisions in the loan documents securing loans to the members, the Rural Utilities Service also exercises control and supervision over the members that borrow from it in such areas as accounting, other borrowings, construction and acquisition of facilities, and the purchase and sale of power.

Historically, federal loan programs providing direct and guaranteed loans from the Rural Utilities Service to electric cooperatives have been a major source of funding for the members. Under the current Rural Utilities Service loan programs, electric distribution borrowers are eligible for loans made by the Federal Financing Bank or other lenders and guaranteed by the Rural Utilities Service. Certain borrowers with either low consumer density or higher than average rates and lower than average consumer income are eligible for special loans that bear interest at an annual rate of 5%. However, Rural Utilities Service loan funds are subject to annual federal budget appropriations, and, due to budgetary and political pressures faced by Congress, the availability and magnitude of these loan funds cannot be assured.

The budget for fiscal year 2023, which began October 2022, includes a loan program level of $6.5 billion. We cannot predict the amount or cost of Rural Utilities Service loans that may be available to the members in the future. For additional information regarding the Rural Utilities Service, see "OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders – *Rural Utilities Service*."

Members' Relationships with Georgia Transmission and Georgia System Operations

Georgia Transmission provides transmission services to our members for delivery of our members' power purchases from us and other power suppliers. Georgia Transmission and the members have entered into member transmission service agreements under which Georgia Transmission provides transmission service to the members pursuant to a transmission tariff. The member transmission service agreements have a minimum term for network service until December 31, 2060. The members' transmission service agreements include certain elections for load growth above 1995 requirements, with notice to Georgia Transmission, to be served by others. These agreements also provide that if a member elects to purchase a part of its network service elsewhere, it must pay appropriate stranded costs to protect the other members from any rate increase that they would otherwise incur. Under the member transmission service agreements, members have the right to design, construct and own new distribution substations.

Georgia System Operations has contracts with each of its members, including Georgia Transmission and us, to provide to them the services that it in turn purchases from Georgia Power under the Control Area Compact, which we co-signed with Georgia System Operations. Georgia System Operations also provides operation services for the benefit of our members through agreements with us, including dispatch of our resources and other power supply resources owned by the members.

For information about our relationship with Georgia System Operations, see "OGLETHORPE POWER CORPORATION – Relationship with Georgia System Operations Corporation."

Member Power Supply Resources

Oglethorpe Power Corporation

In 2022, we supplied approximately 58% of the retail energy requirements of our members. Pursuant to the wholesale power contracts, we supply each member energy from our generation resources based on its fixed percentage capacity cost responsibility, which are take-or-pay obligations. See "OGLETHORPE POWER CORPORATION – Wholesale Power

Contracts." Our members satisfy all of their requirements above their purchase obligations to us with purchases from other suppliers as described below.

Contracts with Southeastern Power Administration

Thirty-three of our members purchase hydroelectric power from the Southeastern Power Administration, or SEPA, under contracts that will continue until terminated by two years' written notice by SEPA or the respective member. At January 1, 2023, the aggregate SEPA allocation of capacity to the members was 570 megawatts plus associated energy. The availability of energy under these contracts is significantly affected by hydrologic conditions, including lengthy droughts. Each member must schedule its energy allocation, and each member, other than Flint EMC, has designated us to perform this function. Pursuant to a separate agreement, we schedule, through Georgia System Operations, our members' SEPA power deliveries. Further, each member may be required, if certain conditions are met, to contribute funds for capital improvements for U.S. Army Corps of Engineers projects from which its allocation is derived in order to retain the allocation.

Smarr EMC

Smarr EMC is a Georgia electric membership corporation owned by 35 of our 38 members. Smarr EMC owns two combustion turbine facilities with aggregate capacity of 733 megawatts. The 35 members participating in these two facilities purchase the output of those facilities pursuant to separate take-or-pay power purchase agreements that will continue until terminated by one year's written notice by Smarr EMC or the respective member.

Green Power EMC

Each of our members is also a member of Green Power Electric Membership Corporation, a power supply cooperative specializing in the purchase of renewable energy for its members. Green Power EMC currently purchases energy from 584 megawatts of solar, low-impact hydroelectric, landfill gas and wood-waste biomass facilities, with an additional 252 megawatts under contract and under construction, with plans to purchase more in the future. Included in this total is energy purchased from Green Power Solar, a for-profit subsidiary of Green Power EMC, which has leased, with an option to purchase, eleven solar facilities with a total of approximately 10 megawatts.

Georgia Energy Cooperative

Fifteen of our members are members of Georgia Energy Cooperative, An Electric Membership Corporation, which owns a 100 megawatt gas turbine facility and also provides other services to its members.

Other Member Resources

Our members obtain their remaining power supply requirements from various sources. All members are parties to requirements contracts or power purchase contracts that meet their incremental requirements. These contracts have remaining terms ranging from 3 to 15 years.

We have not undertaken to obtain a comprehensive list of member power supply resources. Any of our members may have committed or may commit to additional power supply obligations not described above.

For information about members' activities relating to their power supply planning, see "OGLETHORPE POWER CORPORATION – Competition" and "OUR POWER SUPPLY RESOURCES – Future Power Resources." In addition to future power supply resources that we may construct or acquire for our members, the members will likely also continue to acquire future resources from other suppliers, including suppliers that may be owned by members.

REGULATION

Environmental

General

As an electric utility, we are subject to a wide range of federal, state and local environmental laws. Air emissions, solid waste disposal, effluent water discharges, and water usage are extensively controlled, closely monitored, and periodically reported. The manner in which various types of wastes can be stored, transported and disposed is also comprehensively regulated.

In general, environmental requirements applicable to the electric power sector are becoming increasingly prescriptive and stringent, and the Environmental Protection Agency, or EPA, intends to propose a number of rules in 2023 that could impact our power plants. Although we have installed an extensive array of environmental control systems at our plants to ensure continued compliance with all existing applicable requirements, including systems to reduce emissions of sulfur dioxide, nitrogen oxides, mercury and other regulated air pollutants, new environmental regulatory requirements could be imposed. Such additional requirements, if adopted, could substantially increase the cost of electric service by requiring modifications in the design or operation of existing facilities. Failure to comply with these requirements could result in us becoming subject to enforcement actions and the assessment of civil penalties. In extreme cases of non-compliance, such enforcement actions could even include the complete shutdown of individual generating units. Certain of our debt instruments also require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current and future environmental laws or regulations. Should we fail to comply with these requirements, it would constitute a default under those debt instruments. Although we intend to comply with all current and future regulations, we cannot guarantee that we will always be in full compliance with every applicable requirement.

Our capital expenditures and operating costs continue to reflect expenses necessary to comply with all applicable environmental requirements and regulations. With the retirement of Plant Wansley in August 2022, our environmental focus at that plant has shifted to the closure of the coal ash ponds and compliance with associated federal and state regulations, including those related to coal combustion residual (CCR) rules that continue to be revised by EPA and may be impacted by ongoing litigation. For further discussion of expected future capital expenditures to comply with environmental requirements and regulations, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Capital Requirements – Capital Expenditures.*"

Air Quality

Environmental regulations adopted at the federal and state levels have had and will continue to have a significant impact on the electric utility industry. The most significant environmental regulations for us continue to be the air regulatory requirements imposed under the Clean Air Act. These requirements include stringent regulations for controlling emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, greenhouse gases, and other air pollutants from affected electric utility units. The EPA has actively regulated emissions under the Clean Air Act and the following are the most significant ongoing Clean Air Act regulatory requirements that affect or may affect our business.

Controls for Meeting Air Quality Standards. Pursuant to the Clean Air Act, EPA sets National Ambient Air Quality Standards (NAAQS) for the following six air pollutants: particulate matter, ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide and lead. EPA is required to review the existing NAAQS every five years to determine whether a tightening of these standards is necessary to protect public health. In 2020, EPA issued a final rule that retained the existing standards for both ground-level ozone and particulate matter (PM). However, in January 2023, EPA published a proposed rule to set the $PM_{2.5}$ NAAQS within a lower range but will not issue a specific numeric ozone standard until the final rule. At this time, it is too early to determine the extent to which, if any, EPA's proposed tightening of the $PM_{2.5}$ standard, if adopted, might have on Plant Scherer and our gas-fired generating units.

In December 2018, EPA published a final rule that established the requirements and procedures that states must follow in implementing the control measures and other applicable requirements necessary to achieve the 2015 NAAQS ozone standard through State Implementation Plans (SIPs). On December 2, 2021, EPA approved Georgia's SIP and determined that the SIP contains adequate control requirement for reducing emissions that will significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS. Those provisions do not have a significant impact on our operations at this time.

While our remaining coal-fired units at Plant Scherer have had control systems installed to reduce emissions and achieve current ambient air quality standards, new or revised NAAQS could lead to additional emissions reduction requirements. Costs of any additional or upgraded pollution control equipment or operating restrictions that could be required because of more stringent NAAQS cannot be determined at this time, neither can we determine such impacts on our coal or natural gas-fired generating units.

Air Quality Summary. We believe that the emission control systems currently installed at Plant Scherer and our natural gas-fired generating units are generally sufficient to meet the air quality requirements described above. However, additional emissions reduction requirements could be imposed on major sources within Georgia, including at our power plants, to remedy any local and interstate transport air quality problems. Subsequent developments, including litigation and new implementation approaches adopted by EPA and Georgia could require significant capital expenditures and increased operating expenses at certain of our generating facilities, particularly Plant Scherer.

Carbon Dioxide Emissions and Climate Change

Emissions of carbon dioxide from our fossil-fueled power plants totaled 9.1 million metric tons in 2022. Compared to 2005, our overall carbon dioxide emissions rate has declined by 39% through a combination of market factors and our commitment to running highly efficient units with lower carbon dioxide emissions rates. From coal alone, our carbon dioxide emissions in 2022 declined by 72% compared to 2005.

On July 8, 2019, EPA issued the final Affordable Clean Energy (ACE) rule to repeal the Clean Power Plan and adopt a replacement rule for regulating carbon dioxide emissions from existing affected coal-fired electric generating units. On June 30, 2022, after the U.S. Court of Appeals for the D.C. Circuit vacated and remanded the ACE rule back to EPA, the U.S Supreme Court in *West Virginia v. EPA* reversed the D.C. Circuit ruling and, in so doing, limited EPA's authority to regulate greenhouse gas emissions as broadly as the Clean Power Plan. EPA has stated that it will undertake a rulemaking to replace the ACE rule, which is expected to place more stringent limitations on carbon dioxide emissions at existing power plants. The ultimate impact of any such rulemaking cannot be determined at this time due to uncertainty regarding multiple key factors, such as the stringency of the carbon dioxide control requirements, the flexibility provided in the final rule for achieving compliance, market factors related to natural gas, as well as the timing and affordability of renewable energy and new technologies.

Additional regulation of carbon dioxide could occur at the federal or state level and such costs could be significant. One example is potential federal legislation that would require stringent reductions in carbon dioxide emissions from all fossil-fueled electric generation facilities nationwide. Another example is related to the Paris Climate Agreement, to which President Biden recommitted the United States effective February 19, 2021. The United States subsequently announced a nationally determined contribution (NDC) under the agreement for reducing domestic carbon dioxide emissions by 50-52% below 2005 economy-wide levels by 2030. In order to meet this target, analyses have indicated that the power sector would have to reduce carbon dioxide emissions by about 80% below 2005 levels by 2030. These NDCs could lead to a wide range of legislative and regulatory actions to help achieve the Paris Climate Agreement's goals. In addition, President Biden has directed federal agencies to address climate change, environmental justice, and other environmental issues. As a result, as discussed above, EPA could take regulatory actions to require more stringent control requirements to reduce carbon dioxide and other emissions under its existing legal authority. At this time, we cannot predict the outcome of any legislative or regulatory changes or the result of potential litigation challenging any of these actions.

Coal Combustion Residuals and Effluent Limitations Guidelines

In 2015, EPA established a comprehensive regulatory program to manage the disposal of coal combustion residuals (CCR) from coal-fired power plants as non-hazardous material under the Resource Conservation and Recovery Act (RCRA). The 2015 CCR rule sets forth requirements for structural integrity assessments, groundwater monitoring, location siting, composite lining, inactive units, closure and post closure, beneficial use recycling, design and operating criteria, recordkeeping, notification, and internet posting for new and existing CCR landfills, CCR surface impoundments and lateral expansions of CCR disposal facilities. In 2022 and early 2023, the EPA issued a number of proposed determinations on requests for extensions of time to close ash ponds. The proposed determinations could affect the Georgia Environmental Protection Division's (EPD) review of the proposed closure plans for the coal ash ponds at Plants Wansley and Scherer. EPA's proposed determinations subsequently were challenged in the U.S. Court of Appeals for the D.C. Circuit in April 2022, and a decision is expected by the end of 2023. We are currently reviewing those proposed determinations to better understand how they may impact our closure plans. However, the ultimate impact of EPA's actions is unknown at this time and subject to the outcome of the litigation and any future EPA and Georgia regulatory actions.

In 2015, the EPA also finalized a rule to revise the effluent limitations guidelines (ELG) that applies to certain wastewater discharges from fossil fuel-fired steam electric power plants, including Plants Scherer and Wansley. Since adopting the CCR and ELG rules, EPA has adopted revisions to the compliance deadlines and substantive requirements of the two rules. However, on March 8, 2023, EPA issued the pre-publication version of a proposed supplemental ELG rule for steam electric generating units that, if finalized, generally would increase the stringency of the current standards. We currently are reviewing the proposed rule and cannot determine at this time how a final rule would impact Plant Scherer.

ELG Rule Changes. In 2017, EPA extended the ELG compliance deadlines set forth in the 2015 ELG rule to meet discharge limitations for scrubber wastewater and bottom ash transport water from affected coal-fired units, including Plants Scherer and Wansley to November 1, 2020. On November 22, 2019, EPA issued a proposed rule to moderate the discharge limitations on these two wastestreams and subsequently published a final ELG reconsideration rule on October 13, 2020. The ELG rule extends the applicability date for scrubber waste water and bottom ash transport water to December 31, 2025, and allows for various subcategories based on planned future operations, including the rule's voluntary incentives program , low utilization, and early retirement of affected units. Units participating in any of the subcategories were required to submit a notice of planned participation.

The notice for Plant Scherer indicated that units 1 and 2 would comply with the ELG rule under the voluntary incentives program. For Plant Wansley the notice indicated that affected units would comply under the early retirement subcategory. The ELG rule allows for transferring between subcategories consistent with certain regulatory requirements, and the notices reserved the right to transfer subcategories if circumstances change.

The ELG rule revisions are expected to increase capital and operating costs of affected units. The impact of the 2020 ELG reconsideration rule also depends on the outcome of challenges to the rule that are currently in the U.S. Court of Appeals for the Fourth Circuit. However, the litigation is being held in abeyance as EPA undertakes the supplemental rulemaking mentioned above. Any revisions that EPA proposed in the supplemental ELG rule and subsequently may finalize could affect our compliance approach. In light of these factors, the impact and ultimate outcome of the ELG rule cannot be determined at this time.

CCR Rule Changes. In 2016, in response to EPA's CCR rulemaking, EPD adopted new requirements to regulate CCR wastes. These new rules incorporated EPA's requirements as well as state-only requirements for managing CCR wastes in Georgia. These state requirements were implemented and are enforced through a permit system that was approved by EPA in December 2019. Once CCR permits are issued by Georgia EPD, federal citizen suits under RCRA to enforce federal CCR requirements incorporated in the state permit are generally no longer allowed and permit challenges will be handled through EPD's existing administrative process. Georgia's existing CCR regulations are not anticipated to have a material impact on our compliance obligations under the federal CCR rule. However, we cannot predict the impact of any changes to Georgia's CCR regulations including potential legislation or litigation.

In 2019, Georgia Power ceased sending CCR to the ash ponds at Plants Scherer and Wansley. Similarly, Georgia Power has installed a new wastewater treatment system that will receive and manage the non-CCR wastestreams at Scherer. As a result, these new closure deadlines have not impacted our operations. Although no litigation related to CCR regulations is now pending, we cannot predict whether there will be any future lawsuits on the requirements for closing these impoundments or remedying any impacts the impoundments may be having on groundwater.

In 2018, Georgia Power applied for CCR permits to close the ash ponds at Plants Scherer and Wansley in place using advanced engineering methods. However, in March 2022, Georgia Power notified the Georgia Public Service Commission of a revised closure proposal for Plant Wansley. Georgia Power’s modified closure plan at Plant Wansley recommends closure by removing the ash from the coal ash pond for several site-specific reasons, including available capacity at an existing on-site landfill due to the retirement of Plant Wansley in August 2022, beneficial use of the coal ash, and managing construction and operational risks of its current closure in place design. Georgia Power’s proposed closure plans and any future revisions are subject to the approval of the Georgia Public Service Commission and EPD. Costs associated with the closure of ash ponds are reflected in the asset retirement obligations discussed below and we routinely update our asset retirement obligations to reflect any future changes in compliance requirements or cost projections. Georgia Power estimates closing activities to be completed in 2032 for both Plants Wansley and Scherer.

On January 11, 2022, EPA issued a number of proposed determinations on requests for extensions of time to close ash ponds. The proposed determinations include the agency’s rationale and current position on closure standards, groundwater monitoring, and corrective action. EPA's actions subsequently were challenged at the U.S. Court of Appeals for the D.C. Circuit, and a decision is expected by the end of 2023. EPA's current position and the outcome of the pending litigation could affect EPD's review of the proposed closure plans for Plants Wansley and Scherer under Georgia's CCR permit program, as well as require changes in the CCR regulations. The outcome of these matters and impact on compliance costs and operations cannot be determined at this time.

Associated CCR and ELG Compliance Costs. We continue to evaluate the requirements associated with existing and future CCR and ELG rules. Based on this ongoing evaluation, we expect to periodically update compliance methods, schedules, and costs. Our current estimates for capital expenditures to comply with the applicable CCR requirements and effluent discharge limitations are estimated to be approximately $300 million for conversion to dry ash handling, landfill construction, and wastewater treatment. This estimate includes $250 million that has already been spent. Additionally, our current estimated expenditures for the settlement of related asset retirement obligations are approximately $550 million to $700 million (in year of expenditure dollars) for the closure and post-closure of existing coal ash ponds and the dry coal ash and gypsum storage areas. Approximately $30 million of this amount has already been incurred. See Note 1 of Notes to Consolidated Financial Statements. More definitive cost estimates will continue to be developed as the processes of rule evaluation, compliance approach and design and construction implementation proceed. The ultimate impacts associated with the federal and state CCR rules and the federal effluent discharge limitations, any revised regulation or legislation at the state or federal level and related litigation challenging such rules, or future legislation cannot be determined at this time. If Georgia's requirements for coal ash disposal are subsequently revised or the proposed closure plans for the CCR surface impoundments at Plants Scherer and Wansley are not approved, our estimated compliance costs could increase materially.

Water Use and Wastewater Issues

In 2015, the U.S. Court of Appeals for the Sixth Circuit stayed a final rule published jointly by EPA and the U.S. Army Corps of Engineers that revised the regulatory definition of waters of the U.S. for all Clean Water Act programs. The final rule would have significantly expanded the scope of federal jurisdiction under the Clean Water Act. Although the rule was not expected to have a substantial direct impact on our existing operations, it would likely have increased permitting and regulatory requirements and costs associated with the siting and permitting of new facilities. In July 2017, EPA and Army Corps of Engineers proposed a two-step process to address the stayed rule and followed that proposal with a supplemental proposed rule in June 2018. The first step replaces the 2015 regulations that defined waters of the U.S. with those that were in effect prior to the 2015 rule. In the second step, EPA proposed a rule in December 2018 replacing the 2015 definition with a revised definition that clarifies and narrows the scope of federal authority under the Clean Water Act. A final rule incorporating the proposed rules was issued on January 23, 2020. The EPA and Army Corps of Engineers have subsequently taken steps to again revise the definition of waters of the U.S. and proposed an interim definition in November 2021 while drafting a revised rule, which was finalized on January 18, 2023. In addition, there is litigation at the U.S. Supreme Court that could affect the newly revised definition, as well as future definitions and rulemakings. While there is minimal direct impact to our operations as a result of the current rule, we cannot determine the ultimate impact of any change to that rule or any litigation challenging various iterations of the rule or any replacement rule at this time.

Other Environmental Matters

We are subject to other environmental statutes including, but not limited to, the Georgia Water Quality Control Act, the Georgia Hazardous Site Response Act, the Toxic Substances Control Act, the Endangered Species Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Emergency Planning and Community Right to Know Act, and the regulations implementing these environmental statutes. We do not believe that our compliance obligations with these statutory and regulatory requirements will have a material impact on our financial condition or operation of our facilities. Changes to any of these laws, however, could affect many areas of our operations. Although compliance with new environmental legislation could have a significant impact on those operations, such impacts cannot be fully determined at this time and would depend in part on the final legislation and the development of implementing regulations.

As an owner, co-owner and/or operator of generating facilities, we are also subject, from time to time, to claims relating to operations and/or emissions, including actions by citizens to enforce environmental regulations and claims for personal injury due to such operations and/or emissions. Likewise, actions by private citizen groups to enforce environmental laws and regulations are becoming increasingly prevalent. We cannot predict the outcome of current or future actions, our responsibility for a share of any damages awarded, or any impact on facility operations. We do not believe, however, that current actions will have a material adverse effect on our financial position, results of operations, or cash flows.

While we will continue to exercise our best efforts to comply with all applicable regulations, there can be no assurance that we will always be in full compliance with all applicable current and future environmental requirements. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could even force the complete shutdown of individual generating units not in compliance with these regulations in some cases. Any additional federal or state environmental restrictions imposed on our operations could result in significant additional compliance costs, including capital expenditures. Such costs could affect future unit retirement and replacement decisions and may result in significant increases in the cost of electric service. The cost impact of future legislation, regulation, judicial interpretations of existing laws or regulations, or international obligations will depend upon the specific requirements thereof and cannot be determined at this time.

Nuclear Regulation

We are subject to the provisions of the Atomic Energy Act of 1954 (the Atomic Energy Act), which vests jurisdiction in the Nuclear Regulatory Commission over the construction and operation of nuclear reactors, particularly with regard to certain public health, safety and antitrust matters. The National Environmental Policy Act has been construed to expand the jurisdiction of the Nuclear Regulatory Commission to consider the environmental impact of a facility licensed under the Atomic Energy Act. Plants Hatch and Vogtle are being operated under licenses issued by the Nuclear Regulatory Commission. All aspects of the construction, operation and maintenance of nuclear power plants are regulated by the Commission. From time to time, new Commission regulations require changes in the design, operation and maintenance of existing nuclear reactors. Operating licenses issued by the Commission are subject to revocation, suspension or modification, and the operation of a nuclear unit may be suspended if the Commission determines that the public interest, health or safety so requires. The operating licenses issued for each unit of Plants Hatch and Vogtle expire in 2034 and 2038, and 2047 and 2049, respectively.

The Nuclear Regulatory Commission issued combined construction permits and operating licenses that allow the completion of construction and operation of two additional units at Plant Vogtle. See "OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*."

Pursuant to the Nuclear Waste Policy Act of 1982, the federal government has the responsibility for the final disposal of commercially produced high-level radioactive waste materials, including spent nuclear fuel. This act requires the owner of nuclear facilities to enter into disposal contracts with the Department of Energy for such material.

Contracts with the Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at Plants Hatch and Vogtle. The Department of Energy failed to begin disposing of spent fuel in 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants, has successfully pursued and continues to pursue legal remedies against the Department of Energy for breach of contract. See Note 1 of Notes to Consolidated Financial Statements for information regarding the status of this litigation.

In November 2013, the U.S. District Court for the District of Columbia ordered the Department of Energy to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the Department of Energy either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. We discontinued paying the fee of approximately $9.2 million annually, based on our ownership interests, in June 2014.

Existing on-site dry storage facilities at Plants Hatch and Vogtle can be expanded to accommodate spent fuel through the expected life of each plant, including Vogtle Units No. 3 and No. 4.

For information concerning nuclear insurance, see Note 10 of Notes to Consolidated Financial Statements. For information regarding the Nuclear Regulatory Commission's regulation relating to decommissioning of nuclear facilities and regarding the Department of Energy's assessments pursuant to the Energy Policy Act for decontamination and decommissioning of nuclear fuel enrichment facilities, see Note 1 of Notes to Consolidated Financial Statements.

Federal Power Act

General

Pursuant to the Federal Power Act, the Federal Energy Regulatory Commission is the federal agency that regulates the nation's bulk power system. We are subject to certain rules and regulations under the Federal Power Act; however, as a borrower from the Rural Utilities Service, we are exempted from certain Federal Energy Regulatory Commission regulations, including rate regulation.

Rocky Mountain

We are subject to the hydropower licensing provisions of the Federal Power Act. Rocky Mountain is a hydroelectric project subject to licensing by the Federal Energy Regulatory Commission. The currently effective Federal Energy Regulatory Commission license to operate the Rocky Mountain project expires in 2026, and we are currently in the process of relicensing the project. We anticipate making a timely application for a new license for the Rocky Mountain project in 2024. See "PROPERTIES – Generating Facilities" and " – The Plant Agreements – *Rocky Mountain"* for additional information.

Upon or after the expiration of the existing license, the United States Government, by act of Congress, may take over the project, or the Federal Energy Regulatory Commission may relicense the project either to the existing licensee or to a new licensee. In the event of takeover or relicensing to another, the existing licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property taken, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property taken. The Federal Energy Regulatory Commission may grant relicenses subject to certain requirements that could result in additional costs. If the Federal Energy Regulatory Commission does not act on the new license application prior to the expiration of the existing license, the commission is required to issue annual licenses, under the same terms and conditions of the existing license, until a new license is issued.

Energy Policy Act of 2005

The Energy Policy Act of 2005 amended the Federal Power Act to authorize the Federal Energy Regulatory Commission to establish an electric reliability organization to develop and enforce mandatory reliability standards and to establish clear responsibility for the commission to prohibit manipulative energy trading practices. In 2006, the Federal Energy Regulatory Commission certified the North American Electric Reliability Corporation, or NERC, as the electric reliability organization. The mandatory reliability standards developed by NERC and approved by the Federal Energy Regulatory Commission impose certain operating, coordination, record-keeping and reporting requirements on us. NERC has delegated day-to-day enforcement of its responsibilities to regional entities and SERC Reliability Corporation is the regional entity to enforce reliability compliance in sixteen central and southeastern states, including Georgia. These entities have the authority to issue fines and penalties for violations of these standards.

As a generator owner and generator operator, we are subject to certain of these mandatory reliability standards. We have established a comprehensive formal compliance program to establish, monitor, maintain and enhance our commitment to electric reliability compliance. This program includes comprehensive cyber security elements designed to protect and preserve our critical information and energy infrastructure systems. Although we intend to comply with all currently effective and enforceable reliability standards, we cannot provide assurance that we will always be in compliance. We are obligated to maintain and retain evidence of compliance with specific requirements. SERC Reliability Corporation also regularly monitors us for compliance with reliability standards. We expect that existing reliability standards will continue to be refined and that new reliability standards will be developed or adopted.

ITEM 1A. RISK FACTORS

The following describes material risks, in management's view, that may affect our business and financial condition or the value of our debt securities. This discussion is not exhaustive, and there may be other risks that we face which are not described below. The risks described below, as well as additional risks and uncertainties presently unknown to us or currently not deemed material, could negatively affect our business operations, financial condition and future results of operations.

Facility Ownership, Operation and Construction Risk Factors

Our participation in the construction of Vogtle Units No. 3 and No. 4 could have a material impact on our financial condition and results of operations.

We are participating in the construction of two additional nuclear units at Plant Vogtle and have committed significant capital expenditures to this endeavor. The construction of large, complex generating plants involves significant financial risk. We rely on Georgia Power and Southern Nuclear as our agents for the oversight of the construction of the additional units at Plant Vogtle and do not exercise direct control over the construction process. As of December 31, 2022, our total investment in the additional Vogtle units was approximately $8.0 billion.

Our current budget for our ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs, allowance for funds used during construction, and a separate Oglethorpe-level contingency, is $8.1 billion and is based on commercial operation dates of June 2023 and March 2024 for Units No. 3 and No. 4, respectively. In June 2022, we exercised the tender option available pursuant to the Global Amendments which caps our capital costs in exchange for a proportionate reduction of our 30% interest in the two new units. Based on the current project budget and schedule and our interpretation of the Global Amendments, we would transfer and release from the lien of the first mortgage indenture approximately 55 megawatts (out of 660 megawatts) to Georgia Power. Our resulting ownership share would decline from 30% to approximately 27.5%. However, if the total project costs exceed the current budget, our ownership share and megawatts could be further reduced.

We and the other Co-owners are responsible for construction costs based on our ownership percentages. Factors that could lead to further cost increases and schedule delays or even the inability to complete this project include:

- performance by Georgia Power as agent for the Co-owners and performance by Southern Nuclear as construction manager;
- performance by Bechtel under the Bechtel Agreement as well as subcontractor and supplier performance, including compliance with the design specifications approved and quality standards set forth by the Nuclear Regulatory Commission;
- changes in labor costs, availability and productivity;
- shortages, delays, increased costs or inconsistent quality of labor, equipment and materials;
- performance by Westinghouse under the Services Agreement;
- design and other licensing-based compliance matters, including inspections and timely submittal by Southern Nuclear of the inspections, tests, analyses, and acceptance criteria documentation and the related investigations, reviews and approvals by the Nuclear Regulatory Commission to authorize fuel load for Unit No. 4;
- engineering or design problems or any remediation related thereto;
- challenges with start-up activities (including major equipment failure or system integration) and/or operational performance;
- contract disputes;
- increases in our cost of debt financing as a result of changes in market interest rates or as a result of construction schedule delays;
- the effects of future COVID-19 variants and related precautionary measures;
- operational readiness, including specialized operator training and required site safety programs;
- delays or failure to receive necessary permits, approvals and other regulatory authorizations;
- the outcome of any legal challenges to the project, including legal challenges to regulatory approvals;
- erosion of public and policymaker support;
- changes in project design or scope;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- adverse weather conditions;
- catastrophic events, natural disasters and future pandemic health events; and
- work stoppages.

As part of its ongoing process, Southern Nuclear continues to evaluate cost and schedule forecasts on a regular basis to incorporate current information available, particularly in the areas of start-up testing and related test results, engineering support, commodity installation, system turnovers and workforce statistics.

Since March 2020, the number of active cases of COVID-19 at the site has fluctuated consistent with the surrounding area and impacted productivity levels and pace of activity completion. As of December 31, 2022, the incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity, substantially all of which occurred in 2020 and 2021, is estimated by Georgia Power to be between $350 million and $438 million and is included in the project budget. Future COVID-19 variants could further disrupt or delay construction, testing, supervisory, and support activities at Vogtle Units No. 3 and No. 4.

On July 29, 2022, Southern Nuclear announced that all Unit No. 3 inspections, tests, analyses, and acceptance criteria documentation had been submitted to the Nuclear Regulatory Commission. On August 3, 2022, the Nuclear Regulatory Commission published its 103(g) finding that the acceptance criteria in the combined license for Unit No. 3 had been met, which allowed for nuclear fuel to be loaded and start-up testing to begin. Fuel load for Unit No. 3 was completed on October 17, 2022. In early 2023, during the start-up and pre-operational testing for Unit No. 3, Southern Nuclear identified and remediated certain equipment and component issues. On March 6, 2023, the Unit No. 3 nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality, a key milestone in the start-up process. Georgia Power has disclosed that it projects an in-service date for Unit No. 3 during May or June 2023. Our current budget reflects our expectation of an in-service date for Unit No. 3 in June 2023. The projected schedule for Unit No. 3 primarily depends on the progression of final component and pre-operational testing and start-up, which may be impacted by further equipment, component and/or other operational challenges.

Georgia Power has disclosed that it projects an in-service date for Unit No. 4 during late fourth quarter 2023 or during the first quarter 2024. Given the remaining work to be done and potential risks associated with completing the work, our current budget anticipates an in-service date for Unit No. 4 in March 2024. Meeting the projected in-service date for Unit No. 4 primarily depends on potential impacts arising from Unit No. 4 testing activities overlapping with Unit No. 3 start-up and commissioning; maintaining overall construction productivity and production levels improving, particularly in subcontractor scopes of work; and maintaining appropriate levels of craft laborers. As Unit No. 4 completes construction and transitions further into testing, ongoing and potential future challenges include the duration of hot functional testing, which commenced on March 20, 2023, and other testing, the pace and quality of remaining commodities installation; completion of documentation to support inspections, tests, analyses and acceptance criteria submittals; the pace of remaining work package closures and system turnovers; and the availability of craft, supervisory and technical support resources.

Ongoing or future challenges for both units also include management of contractors and vendors; subcontractor performance; and/or related cost escalation. New challenges also may continue to arise, as Unit No. 3 completes start-up and commissioning and Unit No. 4 moves further into testing and start-up, which may result in required engineering changes or remediation related to plant systems, structures or components (some of which are based on new technology that only within the last few years began initial operation in the global nuclear industry at this scale). These challenges may result in further schedule delays and/or cost increases. Further delays into the summer months of 2023 or 2024 could also require that our members acquire replacement power, potentially at a higher cost, for the power anticipated to be available from Units No. 3 and No. 4, respectively.

There have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to ensure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction. With the receipt of the Nuclear Regulatory Commission's 103(g) finding, Unit No. 3 is now under the Nuclear Regulatory Commission's operating reactor oversight process and must meet applicable technical and operational requirements contained within its operating license. Various design and other licensing-based compliance matters, including the timely submittal by Southern Nuclear of the inspections, tests, analyses, and acceptance criteria documentation and the related reviews and approvals by the Nuclear Regulatory Commission necessary to support authorization to load fuel for Unit No. 4, may arise, which may result in additional license amendment requests or require other resolution. If any license amendment requests or other licensing-based compliance issues, including inspections, tests, analyses, and acceptance criteria for Unit No. 4, are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

Pursuant to the Global Amendments, Georgia Power agreed to mitigate certain financial exposure for the other Co-owners. In the event that construction costs exceed the EAC in VCM 19 by more than $800 million up to $2.1 billion, Georgia Power will be responsible for an increasing percentage of construction costs, subject to exceptions, such as costs related to a force majeure event, up to a maximum of an additional $180 million, and each Co-owner would maintain its existing ownership interest. If the EAC is revised and exceeds the EAC in VCM 19 by more than $2.1 billion, each of the Co-owners, other than Georgia Power, has a one-time option to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Co-owner's share of construction costs actually incurred in excess of the EAC in VCM 19 report plus $2.1 billion. If any Co-owner elects to exercise this tender option, Georgia Power would have the option to cancel the project in lieu of accepting the offer to purchase a portion of the Co-owner's ownership interest. If Georgia Power does not elect to cancel the project, then Georgia Power must accept the offer, and the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the percentage of the cumulative amount of construction costs paid by such tendering Co-owner as of the commercial operation date of Vogtle Unit No. 4. This option to tender a portion of our interest to Georgia Power upon such a budget increase allows us to freeze our construction budget associated with the Vogtle project in exchange for a proportionate reduction of our 30% ownership interest.

The VCM 19 total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. At December 31, 2021, budget increases since VCM 19 reached $3.4 billion for all Co-owners. As a result of those increases, we believe that the tender option was triggered at the Co-owner construction budget vote on February 14, 2022 and that Georgia Power's increased responsibility for certain construction costs as described above commenced in March 2022.

On June 17, 2022, we notified Georgia Power of our election to exercise the tender option and cap our capital costs in exchange for a proportionate reduction of our 30% interest in the two new units. Our decremental ownership interest will be calculated and conveyed to Georgia Power after both Vogtle units are placed in service. Based on the current project budget, our schedule assumptions, and our interpretation of the Global Amendments, our project budget is $8.1 billion and we expect to transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share will decline from 30% to approximately 27.5%. By exercising the tender option and based on current assumptions, we estimate that we will avoid incurring approximately $530 million in construction costs associated with the project. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced. On July 26, 2022, the City of Dalton notified Georgia Power that it had elected to exercise its tender option.

We and Georgia Power do not agree on certain aspects of the tender option, including the dollar amount that triggers our option to tender a portion of our ownership interest to Georgia Power under the tender option or the extent to which costs that are the result of a force majeure event (such as COVID-19) impact the point at which the tender option is triggered. For purposes of determining when our option to tender has been triggered, the Global Amendments do not exclude costs resulting from force majeure events (such as COVID-19) from the calculation of when the EAC in VCM 19 plus $2.1 billion has been reached. We and Georgia Power also do not agree on the dollar amount that triggers Georgia Power's increased responsibility for certain construction costs as described above, and the extent to which costs that are the result of a force majeure event (such as COVID-19), impact the calculation of the point at which Georgia Power's increased responsibility for certain construction costs as described above is triggered. The exclusion of costs resulting from a force majeure event (such as COVID-19) in the Global Amendments only applies to Georgia Power's increased cost responsibility during the time period when construction costs exceed the EAC in VCM 19 by $800 million to $2.1 billion.

Accordingly, in March 2022, we notified Georgia Power of a billing dispute with regards to both the starting dollar amount and the application of costs resulting from a force majeure event and how such amounts impact the thresholds and timing of the cost-sharing and tender option provisions. On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County, Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim against us seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power's related financial obligations. Based on the current project budget and Georgia Power's interpretation of the Global Amendments, our project budget would be $8.65 billion, and we would incur approximately $530 million of additional construction costs (excluding related financing costs) and retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

Pursuant to the Joint Ownership Agreements, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Global Amendment provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more over the most recently approved schedule. The most recent schedule extensions, which reflected a cumulative delay of over a year for each unit from the schedules approved in the seventeenth VCM report, triggered the requirement for the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 to vote to continue construction, and the Co-owners unanimously voted to continue construction.

The Global Amendments provide that Georgia Power may cancel the project at any time in its sole discretion. In the event that Georgia Power determines to cancel the project or fewer than 90% of the Co-owners vote to continue construction upon the occurrence of a subsequent project adverse event, we and the other Co-owners would assess our options for the Vogtle project. If the investment were to be written off, we would seek regulatory accounting treatment to amortize the investment over a long-term period, which requires the approval of our board of directors, and we would submit the regulatory accounting treatment details to the Rural Utilities Service for its approval. Further, if Georgia Power or the Co-owners decided to cancel the project, the Department of Energy would have the discretion to require that we repay all amount outstanding under the loan guarantee agreement over a five-year period.

The ultimate outcome of these matters cannot be determined at this time; however, these risks could continue to impact the in-service dates and our cost for the additional units at Plant Vogtle which would increase the cost of electric service we provide to our members and, as a result, could affect their ability to perform their contractual obligations to us.

We own and are participating in the construction of nuclear facilities which give rise to environmental, regulatory, financial and other risks.

We own a 30% undivided interest in Plant Hatch and Plant Vogtle, each of which is a two-unit nuclear generating facility, and which collectively account for approximately 15% of our total gross generating capacity and 36% of our energy generated during 2022. Our ownership interests in these facilities expose us to various risks, including:

- potential liabilities relating to harmful effects on the environment and human health and safety resulting from the operation of these facilities and the on-site storage, handling and disposal of radioactive materials, including spent nuclear fuel;
- uncertainties with respect to the technological and financial aspects of and the ability to maintain and anticipate adequate capital reserves for decommissioning these facilities at the end of their operational lives;
- significant capital expenditures relating to maintenance, operation, security and repair of these facilities, including repairs or modifications required by the Nuclear Regulatory Commission;
- potential liabilities arising out of nuclear incidents caused by natural disasters, terrorist attacks, cyber security attacks or otherwise, including the payment of retrospective insurance premiums, whether at our own plants or the plants of other nuclear owners; and
- uncertainties with respect to the off-site storage and disposal of spent nuclear fuel in the event that on-site storage is not sufficient.

The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. If our nuclear facilities were found to be out of compliance with applicable requirements, the Nuclear Regulatory Commission may impose fines or shut down one or more units of these facilities until compliance is achieved. Revised safety requirements issued by the Nuclear Regulatory Commission have, in the past, necessitated substantial capital expenditures at other nuclear generating facilities.

Further, a major incident at a nuclear facility anywhere in the world could cause the Nuclear Regulatory Commission to limit or prohibit the operation or licensing of any domestic nuclear unit. While we have no reason to expect a serious incident at either of our nuclear plants, if an incident did occur, it could result in substantial cost to us.

We maintain an internal fund and an external trust fund to pay for the estimated cost of decommissioning our existing nuclear facilities. We continue to collect and deposit additional funds into the internal fund. The internal and external funds are invested in a diversified mix of equity and debt securities, the performance of which is subject to market performance risks. If the values of the investments in the funds significantly decrease or the anticipated decommissioning costs significantly increase, it is possible that the decommissioning costs could exceed the funds available and we would have to collect additional revenue from our members to pay the unfunded costs.

In addition to our ownership of existing nuclear units, we are participating with the other Co-owners of Plant Vogtle in the construction of two additional nuclear units at the Plant Vogtle site. See "BUSINESS—OUR POWER SUPPLY RESOURCES—Future Power Resources—*Plant Vogtle Units No. 3 and No. 4*."

We could be adversely affected if we or third parties operating certain of our co-owned facilities are unable to continue to operate our facilities in a successful manner.

The operation of our generating facilities may be adversely impacted by various factors, including:

- the risk of equipment and information technology failure or operator error;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- physical or cyber attacks against us or key suppliers or service providers;
- interruptions or shortages in fuel, water or material supplies;
- transmission constraints or disruptions;
- compliance with electric reliability organizations' mandatory reliability and record keeping standards, including mandatory cyber security standards;
- the ability to maintain a qualified workforce;
- an environmental event, such as a spill or release;
- labor disputes; or
- severe weather or catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events, such as COVID-19, or similar occurrences.

A severe drought could reduce the availability of water and restrict or prevent the operation of certain generating facilities. Other negative events such as those discussed above could also interrupt or limit electric generation or increase the cost of operating our facilities, which could have the effect of increasing the cost of electric service we provide to our members and affect their ability to perform their contractual obligations to us.

Further, a significant percentage of our energy is generated at co-owned facilities that are operated by Georgia Power and Southern Nuclear. We rely on these third parties for the continued operation of these facilities to avoid potential interruptions in service from these facilities. If these third parties are unable to operate these facilities, the cost of electric service we provide to our members, or the cost of replacement electric service, may increase. See "BUSINESS—OGLETHORPE POWER CORPORATION—Relationship with Georgia Power Company" and "Properties—Co-Owners of Plants" and "—Plant Agreements" for discussions of our relationship with Georgia Power and our co-owned facilities.

If we are unable to obtain an adequate supply of fuel, our ability to operate our facilities could be limited.

We obtain our fuel supplies, including natural gas, coal and uranium, from a number of different suppliers. Any disruptions in our fuel supplies, including disruptions due to weather, environmental regulations, inadequate infrastructure, labor relations, workforce shortages or other factors affecting our fuel suppliers, could result in us having insufficient levels of fuel supplies. A number of commodities, including natural gas and coal, have recently been affected by broader supply chain challenges and commodity availability constraints. Natural gas supplies may be unavailable due to increased demand during periods of exceptionally cold weather and are also subject to disruption due to natural disasters and similar events or infrastructure failure. In the second half of 2021 and throughout 2022, we managed rail-related delays in connection with our coal supply. Additionally, there are only a few facilities that fabricate fuel for our nuclear units and if there was an interruption in production at one of those facilities, it could impact our ability to obtain fuel for our nuclear generating facilities on a timely basis. Any failure to maintain access to or an adequate inventory of fuel supplies could require us to operate other generating plants at a higher cost or require our members to purchase higher-cost energy from other sources and, as a result, affect our members' ability to perform their contractual obligations to us.

We and the other co-owners may retire our remaining coal-fired generation units in advance of our currently assumed retirement dates which could result in rate recovery challenges.

We own or lease a 60% interest in Plant Scherer Units No. 1 and No. 2 which constitutes 14% of our total summer planning reserve capacity. The percentage of gross energy generated by coal-fired resources we sell to our members has decreased from 45% in 2008 to 10% in 2022. This decrease was largely driven by other generation resources being more economical, our acquisition of additional natural gas-fired resources and the retirement of Plant Wansley in August 2022. Additional lower cost generation could further displace our remaining coal-fired generation which may make continued operation uneconomical.

In addition to these pressures, potential new environmental standards could require additional capital expenditures or operating costs that make continued operation of the remaining units uneconomical. Some banking and insurance companies have also voluntarily implemented policies to limit lending to, investing in and insuring utilities that significantly rely on coal-fired generation assets. We are not aware that any of those policies have directly impacted us to date. Similar pressures on coal producers have also increased and could impact our price and supply of coal.

Early retirement of our coal units could require us to recover the undepreciated costs for the unit over a shorter period. Plant Wansley was retired in August 2022. In connection with retiring Plant Wansley, we deferred a portion of the accelerated depreciation expense and are recovering the deferred costs over an extended period. The ownership agreements for Plant Scherer, of which we own or lease 60% in each of Units No. 1 and No. 2, require the consent of participants owning at least 75% of the undivided ownership interest in that unit with respect to any decision to retire the unit. In February 2022, Georgia Power, who owns an 8.4% ownership interest in each of Scherer Units No. 1 and No. 2, filed an integrated resource plan with the Georgia Public Service Commission that noted Georgia Power is evaluating the potential retirement Scherer Units No. 1 and No. 2 in 2028. We have not made a decision regarding the retirement of Plant Scherer Units No. 1 or No. 2 prior to the end of our estimated useful life for the units. We will continue to evaluate the reliability, economics and related environmental requirements of Scherer Units No. 1 and No. 2 in order to provide our members with a balanced, reliable and cost-effective generation portfolio.

The ultimate impact of an early retirement on us and our members would depend on several factors, including the proposed retirement date, our ability to recover costs after the retirement date, the price and availability of any replacement energy and cannot be determined at this time. In order to mitigate the rate impact of any early retirement on our members, we would likely apply for regulatory accounting treatment to spread the early retirement costs over an extended period. These increased costs could affect our members' ability to perform their contractual obligations to us.

The operational life of some of our generating facilities exposes us to potential costs to continue to meet efficiency, reliability and environmental compliance standards.

Many of our generating facilities were constructed more than 35 years ago and, even if maintained in accordance with good engineering practices, will require significant capital expenditures in order to maintain efficient and reliable operation. Potential operational issues associated with the age of the plants may lead to unscheduled outages, a generating facility being out of service for an extended period of time, or other service-related interruptions. Further, maintaining facility availability and compliance with applicable efficiency, reliability and environmental standards may require significant capital expenditures or operating reductions at certain of our facilities and we may determine to reduce or cease operations at those facilities in order to avoid such capital expenditures or to meet such standards. These expenditures and service interruptions could have the effect of increasing the cost of electric service we provide to our members and, as a result, could affect our members’ ability to perform their contractual obligations to us.

Financial Risk Factors

Our access to, and cost of, capital could be adversely affected by various factors, including market conditions, limitations on the availability of federally-guaranteed loans and our credit ratings. Significant constraints on our access to, or increases in our cost of, capital may limit our ability to execute our business plan by impacting our ability to fund capital investments and could adversely affect our financial condition and results of operations.

We rely on access to external funding sources as a significant source of liquidity for capital expenditures and acquisitions not satisfied by cash flow generated from operations. Unlike most investor-owned utilities, electric cooperatives cannot issue equity securities and therefore rely almost entirely on debt financing.

In connection with our share of the cost to construct the additional units at Plant Vogtle, we have obtained an aggregate of $4.6 billion in loans from the Federal Financing Bank and a related loan guarantee from the Department of Energy. As of December 31, 2022, we had fully drawn those loans to fund $4.6 billion of eligible project costs with these loans. Based on our current $8.1 billion budget for Vogtle Units No. 3 and No. 4, we anticipate that we will need to raise up to $1.0 billion of additional long-term funding in the capital markets through 2024, including approximately $486 million that will be needed to refinance Department of Energy-guaranteed loans that mature before the in-service date of Vogtle Unit No. 4.

Historically, we relied on federal loan programs guaranteed by the Rural Utilities Service, a branch of the U.S. Department of Agriculture, in order to meet a significant portion of our long-term financing needs, typically at a cost that was lower than traditional capital markets financing. However, the availability and magnitude of Rural Utilities Service funding levels are subject to the annual federal budget appropriations process, and therefore are subject to uncertainty because of budgetary and political pressures faced by Congress. If the amount of this funding available to us in the future is decreased or eliminated, we would seek alternative sources of debt financing in the traditional capital markets which would likely be at a higher cost.

Our access to both short-term and long-term capital market funding remains an important factor in our financing plans, particularly in light of the significant amount of projected capital investment and recent acquisitions. We have entered into multiple credit agreements that provide significant short-term and medium-term liquidity and have successfully accessed the capital markets in the past to satisfy our long-term borrowing needs. We believe that we will be able to maintain sufficient access to the short-term and long-term capital markets based on our current credit ratings. However, our credit ratings reflect the views of the rating agencies, which could change at any point in the future. If one or more rating agencies downgrade us and potential investors take a similar view, our borrowing costs would likely increase and our potential pool of investors, funding sources and liquidity could decrease. In addition, if our credit ratings are lowered below investment grade, collateral calls may be triggered under certain agreements and contracts which would decrease our available liquidity.

Our borrowing costs are also affected by prevailing interest rates, which increased over the course of 2022. If interest rates have increased at the time we issue fixed rate debt or reset the interest rates on our variable rate debt, our interest costs will increase and our financial condition and future results of operations could be adversely affected.

In addition, market disruptions could constrain, at least temporarily, lenders' willingness or ability to perform their obligations under existing credit agreements and our ability to access additional sources of capital on favorable terms or at all. These disruptions include:

- instability in domestic or foreign financial markets;
- a tightening of lending and lending standards by banks and other credit providers;
- the overall health of the energy and financial industries;
- economic downturns or recessions;
- future impacts of the COVID-19 pandemic or other pandemic health events;
- negative events in the energy industry, such as the bankruptcy of an unrelated energy company or the occurrence of a significant natural disaster;
- war or threat of war; and
- terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

Further, an increasing number of lenders and investors are taking into account environmental, social and corporate governance criteria when making lending and investment decisions. Although we are not aware of any instances where our access to capital was limited due to these criteria, such considerations could potentially limit the number of lenders or investors who are willing to lend capital to us or other utility companies in the future.

If our ability to access capital becomes significantly constrained or more expensive for any of the reasons stated above or for any other reason, our ability to finance ongoing capital expenditures or future acquisitions could be limited and our financial condition and future results of operations could be adversely affected.

Our capital expenditures, particularly in relation to the additional units under construction at Plant Vogtle, are projected to be significant and will continue to increase our debt, which is constraining certain of our financial metrics and may also adversely affect our credit ratings which would likely increase our borrowing costs and could decrease our access to capital.

We are in the midst of a multi-year capital spending plan to fund our participation in the construction of Vogtle Units No. 3 and No. 4 and our investment as of December 31, 2022 was $8.0 billion. We have also acquired two natural gas facilities since 2021. As we have financed generation assets in the past, we are relying on external funding to finance the Vogtle units and the recent acquisitions. As of December 31, 2022, we had $11.9 billion of long-term debt outstanding, an increase of $7.7 billion since 2009, when construction of the new Vogtle units commenced. At the completion of the Vogtle expansion, we expect that the amount of our outstanding debt will be approximately $12.4 billion. In addition to the increase in absolute dollars, our debt has been increasing as a percentage of our total capitalization, which has constrained our equity ratio. Furthermore, our debt service payment obligations have increased, which has affected certain other financial metrics. Increased debt and the related impacts on our financial metrics could negatively impact our credit ratings. Any downgrade in our credit ratings would likely increase our borrowing costs and could decrease our access to the credit and capital markets.

In order to increase financial coverage during this period of generation expansion, our board of directors has approved budgets to achieve margins for interest ratios greater than the minimum 1.10 margins for interest ratio required under our first mortgage indenture. We have achieved the board-approved margins for interest ratio each year, and for 2023 our board of directors again approved a margins for interest ratio of 1.14.

Changes in fuel prices could have an adverse effect on our cost of electric service.

We are exposed to the risk of changing prices for fuels, including natural gas, coal and uranium. Our primary fuel price exposure is to natural gas and, for 2022, natural gas expenses constituted 83% of our total fuel costs. We have taken steps to manage this exposure by entering into natural gas swap arrangements designed to manage potential fluctuations in our power rates due to changes in the price of natural gas. We have also entered into fixed or capped price contracts for some of our coal requirements. The operator of our nuclear plants manages price and supply risk through use of long-term fixed or capped price contracts with multiple vendors of uranium ore mining, conversion and enrichment services. However, these arrangements do not cover all of our and our members' risk exposure to increases in the prices of fuels. Further, changes in the utilization of different generation resources may subject us to greater fuel price volatility. Historically, natural gas prices have been more volatile than other fuel sources. In 2021 and 2022, market prices for natural gas were significantly higher than the relatively low market prices prevalent in recent years. Further, geopolitical events or conflicts and the availability of shale gas and potential regulations affecting its accessibility and transport may have a material impact on the cost and supply of natural gas. Increases in fuel prices could significantly increase the cost of electric service we provide to our members and affect their ability to perform their contractual obligations to us.

Our ability to meet our financial obligations could be adversely affected if our members fail to perform their contractual obligations to us.

We depend primarily on revenue from our members under the wholesale power contracts to meet our financial obligations. Our members are our owners, and we do not control their operations or financial performance.

Under current Georgia law, our members generally have the exclusive right to provide retail electric service in their respective territories, subject to limited exceptions. Parties have unsuccessfully sought and will likely continue to seek to advance legislative proposals that will directly or indirectly affect the Georgia Territorial Act in order to allow increased retail competition in our members' service territories which could affect our members' financial performance. Further, our members must forecast their load growth and power supply needs. If our members acquire more power supply resources than needed, whether from us or other suppliers, or fail to acquire sufficient resources, our members' rates could increase excessively and affect their financial performance. Also, in times of weak economic conditions, sales by our members may not be sufficient to cover costs without rate increases, and our members may not collect all amounts billed to their consumers. Although each member has financial covenants to set rates to maintain certain margin levels and our members' rates are not regulated by the Georgia Public Service Commission, pressure from their consumer members not to raise rates excessively could affect financial performance. Thus, we are exposed to the risk that one or more members could default in the performance of their obligations to us under the wholesale power contracts. Our ability to satisfy our financial obligations could be adversely affected if one or more of our members, particularly one of the larger members, defaulted on their payment obligations to us. Although the wholesale power contracts obligate non-defaulting members to pay the amount of any payment default pursuant to a pro rata step-up formula, there can be no guarantee that the non-defaulting members would be able to fulfill this obligation.

Regulatory, Legislative and Legal Risk Factors

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years. Potential new or stricter environmental laws and regulations, including those designed to address air and water quality, coal combustion residuals and other matters, may result in significant increases in compliance costs or operational restrictions.

As with most electric utilities, we are subject to extensive federal, state and local environmental requirements which regulate, among other things, air pollutant emissions, wastewater discharges and the management of hazardous and solid wastes. Compliance with these requirements requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities. Through 2022, we have spent approximately $1.1 billion on capital expenditures at our facilities to achieve and maintain compliance with Georgia's "multi-pollutant rule" and EPA's MATS, two air quality control regulations that have had a significant impact on our business to date. In addition, as of December 31, 2022, we have spent approximately $250 million on capital expenditures related to coal ash handling and ELG compliance, and expect to spend approximately $50 million more in the near future.

The EPA is expected to release several proposed rules or revised standards over the course of 2023, including for greenhouse gas emissions. More stringent or new standards could require us to modify the design or operation of existing facilities and result in significant increases in the cost of electricity or decreases in the amount of energy (due to operational constraints) provided to our members.

In April 2015, the EPA published a final rule to regulate coal combustion residuals from electric utilities as solid wastes. To comply with this rule, the ash ponds at Plants Wansley and Scherer ceased receiving new coal ash in early 2019. We and Georgia Power initially anticipated utilizing advanced engineering methods to close the existing ash ponds in place and proposed such plans to the Georgia EPD in 2018. However, in March 2022, Georgia Power notified the Georgia Public Service Commission of a revised closure proposal for Plant Wansley that would remove the ash from the coal ash pond for several site-specific reasons. Georgia Power's proposed closure plans have been approved by the Georgia Public Service Commission but remain subject to EPD approval, and we cannot predict when they will be approved or whether either closure plan will require modifications. Costs associated with the closure of the ash ponds are reflected in the asset retirement obligations discussed below. In 2022 and early 2023, the EPA issued a number of proposed determinations on requests for extensions of time to close ash ponds. The proposed determinations could affect EPD's review of the proposed closure plans for Plants Scherer and Wansley. If Georgia's requirements for coal ash disposal are subsequently revised or the proposed closure plans are not approved, our estimated compliance costs could increase materially. In September 2015, the EPA also finalized a rule to revise the ELG that apply to certain wastewater discharges from nuclear and fossil fuel-fired steam electric power plants. This rule was later revised in October 2020 for scrubber wastewater and bottom ash transport. However, EPA intends to again revise the ELG rule through a supplemental rule, which is expected to be released in spring 2023. We have already begun investing in facility upgrades to meet the coal combustion residuals rule and effluent limitations guidelines, and estimate our total capital cost for compliance to be approximately $300 million of which $250 million has been spent. Expenditures for the settlement of related asset retirement obligations are approximately $550 million to $700 million (in year of expenditure dollars), approximately $30 million of which has already been spent. We continue to review the ultimate cost of these rules on our co-owned coal facilities.

Litigation relating to environmental issues, including claims of property damage, personal injury or common law nuisance caused by plant emissions, including greenhouse gases, wastewater discharges or solid waste disposal, including coal combustion residuals, is generally increasing throughout the U.S. Likewise, actions by private citizen groups to enforce environmental laws and regulations are also becoming increasingly prevalent.

While we will continue to exercise our best efforts to comply with all applicable regulations, there can be no assurance that we will always be in compliance with all current and future environmental requirements. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete shutdown of individual generating units not in compliance with these regulations. Any additional federal or state environmental restrictions imposed on our operations could result in significant additional compliance costs, including capital expenditures. Such costs could affect future unit retirement and replacement decisions and may result in significant increases in the cost of electric service. The cost impact of future legislation, regulation, judicial interpretations of existing laws or regulations, or international obligations will depend upon the specific requirements thereof and cannot be determined at this time. For additional information regarding certain environmental regulations to which our business is subject, see "BUSINESS —REGULATION—Environmental."

Potential legislative and regulatory actions intended to address climate change and to reduce greenhouse gas emissions, including carbon dioxide, may result in significant compliance costs or expenses.

Concerns regarding climate change continue to increase and the responses to those concerns by policymakers, regulators, investors, consumers and other stakeholders may affect us and our members in various ways. The costs associated with legislative or regulatory actions intended to reduce greenhouse gas emissions could be significant.

President Biden has signed a number of executive orders directing federal agencies to address climate change, environmental justice, and other environmental issues. President Biden also recommitted the United States to the Paris Climate Agreement effective February 19, 2021. In April 2021, under the agreement's format, the United States announced a NDC for reducing economy-wide carbon dioxide emissions by 50-52% below 2005 levels by 2030. In order to meet the

United States NDC, analyses indicate that the power sector would have to reduce carbon dioxide emissions by about 80% below 2005 levels by 2030. As a result of these actions, future legislation or regulations at the federal level may emerge and create new requirements and operational hurdles. In addition, states continue to initiate increasingly stringent environmental and climate-related regulations.

The EPA has stated its intention to propose a replacement rule for the Affordable Clean Energy (ACE) rule in 2023. The ACE rule, issued in 2019 to replace the Clean Power Plan, addresses carbon dioxide emissions from coal plants and requires states to develop unit-specific standards of performance. On June 30, 2022, after the U.S. Court of Appeals for the D.C. Circuit vacated and remanded the ACE rule back to EPA, the U.S. Supreme Court in West Virginia v. EPA reversed the D.C. Circuit ruling and, in so doing, limited EPA's authority to regulate greenhouse gas emissions as broadly as the Clean Power Plan. The EPA has stated that it will undertake a rulemaking to replace the ACE rule. Although the form of the replacement rule is not known at this time, it is likely to place more stringent limitations on carbon dioxide emissions at existing power plants.

Based on these developments, and national trends more generally, we expect legislative and regulatory efforts to reduce the potential impacts of climate change and limit greenhouse gas emissions, including carbon dioxide, to continue. For example, the Inflation Reduction Act of 2022 includes significant financial incentives to accelerate the U.S. transition to a lower greenhouse gas emitting economy. Congress has also recently considered proposals that would mandate significant emissions reductions or increases in clean energy generation from the power sector. Passing new climate legislation, whether in the form of a carbon tax, a clean electricity standard or another proposal, remains challenging in the near-term. The timing, cost and effect of any future laws or regulations attempting to address climate change and reduce greenhouse gas emissions are uncertain. If adopted, however, such laws or regulations could impose operational restrictions on affected generating facilities and impose substantial costs on our business, particularly at Plant Scherer.

General Business Risk Factors

Technology and information systems utilized by us, our members and third parties with whom we do business are subject to risk of failure, loss of access or cybersecurity breaches which could affect our ability to operate and expose us to litigation, regulatory action and reputational harm.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure, which are part of broader interconnected systems. Our generation assets and information technology systems, or those of our co-owned plants, could be directly or indirectly affected by deliberate or unintentional cyber incidents. Since our generation resources are part of the nation’s energy infrastructure system, we are at an increased risk of cyberattack. We and our third party vendors have been subject to attempts to gain unauthorized access to our respective technology systems and confidential data and attempts to disrupt our operations. To date, none of the attempts on our systems have been successful; however, we cannot guarantee that our security efforts will prevent, detect or limit future attempts to breach or compromise our technology and information systems. If our technology systems were to be breached or otherwise fail, we may be unable to fulfill critical business functions, including the operation of our generation assets and our ability to effectively maintain certain internal controls over financial reporting. Further, our generation assets rely on an integrated transmission system to deliver power to our members, and a disruption of this transmission system could negatively impact our ability to do so. In order to reduce the likelihood and severity of any cyber intrusion, we have comprehensive cyber security programs designed to protect and preserve the confidentiality, integrity and availability of data and systems. Despite these protections, a major cyber incident could result in significant business disruption and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including fines, and an adverse effect on our reputation.

Advances in power generation and energy storage technologies, including decreasing renewable energy costs and the broad adoption of distributed generation technologies, in our members' service territories could result in the cost of our electric service being less competitive.

Our business model is to provide our members with wholesale electric power at the lowest possible cost. A key element of this model is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. Renewable energy, distributed generation or energy storage technologies currently exist or are in development, such as large-scale batteries, fuel cells, micro turbines, windmills and solar cells, some of which are capable of producing or storing electric power at costs that are comparable with, or lower than, our cost of generating power. Incentives for renewable energy generation to facilitate the transition to lower-carbon energy sources included in the Inflation Reduction Act could accelerate the adoption and deployment of such technologies. If these technologies were to develop sufficient economies of scale and be broadly adopted in our members’ service territories, it could adversely affect our ability to recover the fixed costs related to and the value of our generating facilities and significantly increase the cost of electric service we provide to our members and affect their ability to perform their contractual obligations to us.

We are subject to the risk that counterparties may fail to perform their contractual obligations which could adversely affect us.

We routinely execute transactions with counterparties in the energy and financial services industries. These transactions include credit facilities, facility construction, co-owner agreements, contracts related to the market price and supply of natural gas and coal, and power sales and purchases. Many of these transactions expose us to the risk that our counterparty may fail to perform its contractual obligations. If a defaulting counterparty is in poor financial condition, we may not be able to recover damages for any breach of contract.

In the context of facility construction, a counterparty's failure to perform its contractual obligations under the applicable agreement could impact the project cost and schedule and potentially project completion.

Regardless of our financial condition, investors' ability to trade our debt securities may be limited by the absence of an active trading market and there is no assurance that any trading market will develop or continue to remain active.

Our debt securities are not listed on any national securities exchange or quoted on any automated quotation system although certain series of our debt securities may be included in a fixed income index. Various dealers have made a market in certain of our debt securities and at times certain of our debt securities have an active trading market; however, other of our debt securities have no active trading market. Dealers or underwriters have no obligation to make a market in any of our debt securities and may terminate any market-making activities at any time, for any reason, without notice. Further, removal from any index may have an adverse effect on the liquidity of the trading market, if any, for our debt securities removed from that index. As a result, we cannot provide any assurance as to the liquidity of any trading market for our debt securities, the ability of holders to sell their debt securities or the price at which holders will be able to sell their debt securities.

Even in an active trading market, future prices of our debt securities will depend on several factors, including prevailing interest rates, the then-current ratings assigned to the debt securities, the number of holders of the debt securities, the amount of our debt securities outstanding, the market for similar securities and our financial and operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Generating Facilities

The following table sets forth certain information with respect to our generating facilities that operated for all or a portion of 2022.

Facilities	Type of Fuel	Percentage Interest	Our Share of Nameplate Capacity (megawatts)	Commercial Operation Date	License Expiration Date
Plant Hatch (near Baxley, Ga.)					
Unit No. 1	Nuclear	30	269.9	1975	2034
Unit No. 2	Nuclear	30	268.8	1979	2038
Plant Vogtle (near Waynesboro, Ga.)					
Unit No. 1	Nuclear	30	348.0	1987	2047
Unit No. 2	Nuclear	30	348.0	1989	2049
Plant Wansley (near Carrollton, Ga.)					
Unit No. 1	Coal	30	259.5	1976	N/A [1,2]
Unit No. 2	Coal	30	259.5	1978	N/A [1,2]
Combustion Turbine	Oil	30	14.8	1980	N/A [1,2]
Plant Scherer (near Forsyth, Ga.)					
Unit No. 1	Coal	60	490.8	1982	N/A [1]
Unit No. 2	Coal	60	490.8	1984	N/A [1]
Rocky Mountain (near Rome, Ga.)	Pumped Storage Hydro	74.61	632.5	1995	2026
Doyle (near Monroe, Ga.)	Gas	100	325.0	2000	N/A [1]
Talbot (near Columbus, Ga.)					
Units No. 1-4	Gas	100	412.0	2002	N/A [1]
Units No. 5-6	Gas-Oil	100	206.0	2003	N/A [1]
Chattahoochee (near Carrollton, Ga.)	Gas	100	468.0	2003	N/A [1]
Effingham (near Savannah, Ga)	Gas	100	597.0	2003	N/A [1]
Washington County (near Sandersville, Ga)					
Unit No. 2	Gas	100	198.9	2003	N/A [1]
Unit No. 3	Gas	100	198.9	2003	N/A [1]
Hawk Road (near Franklin, Ga.)	Gas	100	500.0	2001	N/A [1]
Hartwell (near Hartwell, Ga.)	Gas-Oil	100	300.0	1994	N/A [1]
Smith (near Dalton, Ga.)					
Unit No. 1	Gas	100	630.0	2002	N/A [1]
Unit No. 2	Gas	100	620.0	2002	N/A [1]

(1) Fossil-fuel fired units do not operate under operating licenses similar to those granted to nuclear units by the Nuclear Regulatory Commission and to hydroelectric plants by the Federal Energy Regulatory Commission.

(2) Plant Wansley was retired on August 31, 2022.

Plant Performance

The following table sets forth certain operating performance information of each of our generating facilities:

Unit	Summer Planning Reserve Capacity[1] (Megawatts)	Equivalent Availability[2] 2022	2021	2020	Capacity Factor[3] 2022	2021	2020
Plant Hatch							
Unit No. 1	262.2	90 %	93 %	83 %	91 %	94 %	83 %
Unit No. 2	264.3	97	90	97	98	90	97
Plant Vogtle							
Unit No. 1	344.5	99	92	93	101	94	95
Unit No. 2	344.7	91	100	90	93	103	92
Unit No. 3	328.0						
Plant Wansley[4]							
Unit No. 1	N/A	79	96	98	17	26	0
Unit No. 2	N/A	94	100	83	14	2	1
Combustion Turbine[5]		53	62	62	0	0	0
Plant Scherer							
Unit No. 1	515.0	78	95	98	38	26	16
Unit No. 2	515.0	93	85	95	15	18	8
Rocky Mountain[6]							
Unit No. 1	272.3	91	77	90	16	14	18
Unit No. 2	272.3	96	75	97	20	18	20
Unit No. 3	272.3	76	76	87	10	11	8
Doyle[6]	283.0	84	81	62	4	2	3
Talbot[6]	682.3	75	77	74	10	5	7
Chattahoochee	466.0	67	94	93	59	73	78
Effingham[8]	500.0	77	89		55	72	
Washington County[6,7]	312.8	100			0		
Hawk Road[6]	486.9	63	65	63	16	10	13
Hartwell[6]	305.5	73	79	81	9	6	6
Smith							
Unit No. 1	658.6	92	94	82	68	69	59
Unit No. 2	658.6	94	92	86	71	69	66
TOTAL	7,744.3						

(1) Summer Planning Reserve Capacity is the amount used for 2023 capacity reserve planning. Washington County's reserve capacity of 312.8 megawatts is unavailable in 2023 due to a power purchase and sale agreement with Georgia Power which expires May 31, 2024.
(2) Equivalent Availability is a measure of the percentage of time that a unit was available to generate if called upon, adjusted for periods when the unit is derated from its rated capacity.
(3) Capacity Factor is a measure of the actual output of a unit as a percentage of its potential output.
(4) Plant Wansley was retired on August 31, 2022.
(5) The Wansley combustion turbine was used primarily for emergency service and was rarely operated except for testing.
(6) Rocky Mountain, Doyle, Talbot, Hawk Road, Hartwell and Washington County, primarily operate as peaking plants, which results in low capacity factors.
(7) Washington County was acquired in December 2022. This table only reflects operating performance following our acquisition. There was no generation during the month of December 2022.
(8) Effingham was acquired in July 2021. This table only reflects operating performance following our acquisition.

The nuclear refueling cycle for Plants Hatch and Vogtle exceeds twelve months. Therefore, in some calendar years the units at these plants are not taken out of service for refueling, resulting in higher levels of equivalent availability and capacity factor. Rail-related delays with coal deliveries and lower natural gas prices relative to the cost of coal have resulted in lower capacity factors at Plants Wansley and Scherer in recent years.

Fuel Supply

For information regarding the electricity generated with each fuel type and its cost, see "MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Results of Operations – *Operating Expenses."*

Coal. Coal for Scherer Units No. 1 and No. 2 is purchased under term contracts and in spot market transactions. As of February 28, 2023, our coal stockpile at Plant Scherer contained a 57-day supply based on continuous operation. Plant Scherer burns sub-bituminous coal purchased from coal mines in the Powder River Basin in Wyoming.

We dispatch our interest in Plant Scherer, but use Georgia Power as our agent for fuel procurement. We currently lease approximately 718 railcars to transport coal. In the second half of 2021 and throughout 2022, we managed rail-related delays in connection with our coal supply.

Nuclear Fuel. Georgia Power, as operating agent, has the responsibility to procure nuclear fuel for Plants Hatch and Vogtle. Georgia Power has contracted with Southern Nuclear to operate these plants, including nuclear fuel procurement. Southern Nuclear has contracted with multiple suppliers for uranium ore, conversion services, enrichment services and fuel fabrication to satisfy nuclear fuel requirements. Most contracts are short to medium-term. The nuclear fuel supply and related services are expected to be adequate to satisfy current and future nuclear generation requirements.

Natural Gas. We purchase the natural gas, including transportation and other related services, needed to operate Doyle, Talbot, Chattahoochee, Effingham, Washington County, Hawk Road, Hartwell, and Smith. We purchase natural gas in the spot market and under agreements at indexed prices. We have entered into hedge agreements to manage a portion of our exposure to fluctuations in the market price of natural gas. We manage exposure to such risks only with respect to members that elect to receive such services. We have entered into long-term firm contracts for transportation of a significant percentage of our anticipated natural gas supply. We also purchase transportation under short-term firm and non-firm contracts. See "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK – Commodity Price Risk."

Co-Owners of Plants

Plants Hatch, Vogtle, Wansley and Scherer Units No. 1 and No. 2 are co-owned by Georgia Power, MEAG, the City of Dalton and us, and Rocky Mountain is co-owned by Georgia Power and us. Each co-owner owns or leases undivided interests in the amounts shown in the following table, which excludes the Plant Wansley combustion turbine. We are the operating agent for Rocky Mountain. Georgia Power is the operating agent for each of the other plants.

	Nuclear				Coal-Fired				Pumped Storage		
	Plant Hatch		Plant Vogtle(2)		Plant Wansley(3)		Plant Scherer Units No. 1 & No. 2		Rocky Mountain		Total
	%	MW(1)	%	MW(1)	%	MW(1)	%	MW(1)	%	MW(1)	MW(1)
Oglethorpe	30.0	539	30.0	1,356	30.0	519	60.0	982	74.6	633	4,029
Georgia Power	50.1	900	45.7	2,066	53.5	926	8.4	137	25.4	215	4,244
MEAG	17.7	318	22.7	1,026	15.1	261	30.2	494	—	—	2,099
Dalton	2.2	39	1.6	72	1.4	24	1.4	23	—	—	158
Total	100.0	1,796	100.0	4,520	100.0	1,730	100.0	1,636	100.0	848	10,530

(1) Based on nameplate ratings.

(2) Plant Vogtle Units No. 3 and No. 4 are currently under construction.

(3) Plant Wansley was retired on August 31, 2022.

Georgia Power Company

Georgia Power is a wholly owned subsidiary of The Southern Company and is engaged primarily in the generation and purchase of electric energy and the transmission, distribution and sale of this energy. Georgia Power distributes and sells energy within the State of Georgia at retail in over 600 communities, including Athens, Atlanta, Augusta, Columbus, Macon, Rome and Savannah, as well as in rural areas, and at wholesale to some of our members, MEAG and two municipalities.

Georgia Power is the largest supplier of electric energy in the State of Georgia. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Georgia Power Company." Georgia Power is subject to the informational requirements of the Exchange Act, and, in accordance therewith, files reports and other information with the SEC.

Municipal Electric Authority of Georgia

The Municipal Electric Authority of Georgia, also known as MEAG, is a state-chartered, municipal joint-action agency that provides capacity and energy to its membership of 49 municipal electric utilities, including 48 cities and one county in the State of Georgia. MEAG has wholesale take-or-pay power sales contracts with each of its 49 participants that extend to June 2054. MEAG is Georgia's third largest power supplier behind Georgia Power and us.

City of Dalton, Georgia

Dalton Utilities is a combined utility that provides electric, gas, water and wastewater services to the city of Dalton, located in northwest Georgia, and some of the surrounding communities.

The Plant Agreements

Plants Hatch, Wansley, Vogtle and Scherer

Our rights and obligations with respect to Plants Hatch, Wansley, Vogtle and Scherer are contained in a number of contracts between Georgia Power and us and, in some instances, MEAG and the City of Dalton. We are a party to four Purchase and Ownership Participation Agreements (Ownership Agreements) under which we acquired from Georgia Power a 30% undivided interest in each of Plants Hatch, Wansley and Vogtle, a 60% undivided interest in Scherer Units No. 1 and No. 2 and a 30% undivided interest in those facilities at Plant Scherer intended to be used in common by Scherer Units No. 1, No. 2, No. 3 and No. 4 (the Scherer Common Facilities). We have also entered into four Operating Agreements (Operating Agreements) relating to the operation and maintenance of Plants Hatch, Wansley, Vogtle and Scherer, respectively. The Ownership Agreements and Operating Agreements relating to Plants Hatch and Wansley are two-party agreements between Georgia Power and us. The Ownership Agreements and Operating Agreements relating to Plants Vogtle and Scherer are agreements among Georgia Power, MEAG, the City of Dalton and us. The parties to each Ownership Agreement and Operating Agreement are referred to as "participants" with respect to each such agreement.

In 1985, in four transactions, we sold our entire 60% undivided ownership interest in Scherer Unit No. 2 to four separate owner trusts established by investors and then leased back the 60% interest. We retained all of our rights and obligations as a participant under the Ownership and Operating Agreements relating to Scherer Unit No. 2 for the term of the leases. We have extended three of the leases to 2027 and the fourth lease to 2031. The leases provide for further lease renewal and also include fair market value purchase options at specified dates. See Note 6 of Notes to Consolidated Financial Statements. In the following discussion, references to participants "owning" a specified percentage of interests include our rights as a deemed owner with respect to our leased interests in Scherer Unit No. 2.

The Ownership Agreements appoint Georgia Power as agent with sole authority and responsibility for, among other things, the planning, licensing, design, construction, renewal, addition, modification and disposal of Plants Hatch, Vogtle, Wansley and Scherer Units No. 1 and No. 2 and the facilities used in common at Plant Scherer. Each Operating Agreement gives Georgia Power, as agent, sole authority and responsibility for the management, control, maintenance and operation of the plant to which it relates. Each Operating Agreement also provides for the use of power and energy from the plant and the sharing of the costs of the plant by the participants in accordance with their respective interests in the plant. In performing its responsibilities under the Ownership and Operating Agreements, Georgia Power is required to comply with prudent utility practices. Georgia Power's liabilities with respect to its duties under the Ownership and Operating Agreements are limited by the terms of these agreements.

Under the Ownership Agreements, we are obligated to pay a percentage of capital costs of the respective plants, as incurred, equal to the percentage interest which we own or lease at each plant. With respect to Scherer Units No. 1 and No. 2, the participants have certain limited rights to disapprove capital budgets proposed by Georgia Power and to substitute alternative capital budgets. With respect to Plants Hatch and Vogtle, any co-owner has the right to disapprove large discretionary capital improvements.

The Scherer Ownership Agreement requires the consent of participants owning at least an aggregate 75% undivided ownership interest in the applicable unit (effectively us and MEAG) for actions with respect to the retirement of all or any part of the applicable unit.

In July 2022, the Georgia Public Service Commission approved Georgia Power's 2022 integrated resource plan. This plan requested the decertification of coal-fired Plant Wansley by August 31, 2022. In accordance with the approved plan, Georgia Power retired Plant Wansley on August 31, 2022. Following the retirement of Plant Wansley, our focus at that plant has shifted to the closure of the coal ash ponds. See "BUSINESS – REGULATION – Coal Combustion Residuals and Effluent Limitations Guidelines". As set forth in the Wansley Ownership Agreement, we are responsible for a proportionate share of the plant retirement and decommissioning costs. See Note 13 of Notes to Consolidated Financial Statements for additional information regarding Plant Wansley's retirement.

In 1993, the co-owners of Plants Hatch and Vogtle entered into the Amended and Restated Nuclear Managing Board Agreement, which provides for a managing board to coordinate the implementation and administration of the Plant Hatch and Plant Vogtle Ownership and Operating Agreements, provides for increased rights for the co-owners regarding certain decisions and allows Georgia Power to contract with a third party for the operation of the nuclear units. In 1997, Georgia Power designated Southern Nuclear as the operator of Plants Hatch and Vogtle, pursuant to the Nuclear Operating Agreement between Georgia Power and Southern Nuclear, which the co-owners had previously approved. In connection with the amendments to the Plant Scherer Ownership and Operating Agreements, the co-owners of Plant Scherer entered into the Plant Scherer Managing Board Agreement which provides for a managing board to coordinate the implementation and administration of the Plant Scherer Ownership and Operating Agreements and provides for increased rights for the co-owners regarding certain decisions, but does not alter Georgia Power's role as agent with respect to Plant Scherer.

The Operating Agreements provide that we are entitled to a percentage of the net capacity and net energy output of each plant or unit equal to our percentage undivided interest owned or leased in such plant or unit. Georgia Power, as agent, schedules and dispatches Plants Hatch and Vogtle. The Plant Scherer ownership and operating agreement allows each co-owner (i) to dispatch separately its respective ownership interest in conjunction with contracting separately for long-term coal purchases procured by Georgia Power and (ii) to procure separately long-term coal purchases. We separately dispatch our ownership share of Scherer Units No. 1 and No. 2.

For Plants Hatch and Vogtle, each participant is responsible for a percentage of operating costs (as defined in the Operating Agreements) and fuel costs of each plant or unit equal to the percentage of its undivided interest which is owned or leased in such plant or unit. For Scherer Units No. 1 and No. 2 and for Plant Wansley, each party is responsible for its fuel costs and for variable operating costs in proportion to the net energy output for its ownership interest, and is responsible for a percentage of fixed operating costs equal to the percentage of its undivided interest which is owned or leased in such plant or unit. Georgia Power is required to furnish budgets for operating costs, fuel plans and scheduled maintenance plans. In the case of Scherer Units No. 1 and No. 2, the participants have limited rights to disapprove such budgets proposed by Georgia Power and to substitute alternative budgets. The Ownership Agreements and Operating Agreements provide that, should a participant fail to make any payment when due, among other things, such nonpaying participant's rights to output of capacity and energy would be suspended.

The Operating Agreements for Plant Hatch and Plant Vogtle will remain in effect with respect to each unit for so long as a Nuclear Regulatory Commission operating license exists for such unit. See "BUSINESS – REGULATION – Nuclear Regulation." The Operating Agreement for Scherer Units No. 1 and No. 2, was recently extended for both units to January 31, 2026, and automatically renews for additional two year terms subject to notice of termination provisions. Upon termination of each Operating Agreement, following any extension agreed to by the parties, Georgia Power will retain such powers as are necessary in connection with the disposition of the property of the applicable plant, and the rights and obligations of the parties shall continue with respect to actions and expenses taken or incurred in connection with such disposition.

In conjunction with the development of additional units at Plant Vogtle, we, Georgia Power, MEAG and the City of Dalton entered into amendments to the Operating Agreement for Plant Vogtle and the Nuclear Managing Board Agreement, and entered into an Ownership Agreement that governs participation in Vogtle Units No. 3 and No. 4. Pursuant to this ownership agreement, Georgia Power has designated Southern Nuclear as its agent for licensing, engineering, procurement, contract management, construction and pre-operation services. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*" for a discussion of our ownership agreements related to Vogtle Units No. 3 and No. 4.

Rocky Mountain

The Rocky Mountain Pumped Storage Hydroelectric Ownership Participation Agreement, by and between us and Georgia Power (the Rocky Mountain Ownership Agreement), appoints us as agent with sole authority and responsibility for, among other things, the planning, licensing, design, construction, operation, maintenance and disposal of Rocky Mountain. The Rocky Mountain Pumped Storage Hydroelectric Project Operating Agreement (the Rocky Mountain Operating Agreement) gives us, as agent, sole authority and responsibility for the management, control, maintenance and operation of Rocky Mountain.

In general, each co-owner is responsible for payment of its respective ownership share of all operating costs and pumping energy costs as well as costs incurred as a result of any separate schedule or independent dispatch. A co-owner's share of net available capacity and net energy is the same as its respective ownership interest under the Rocky Mountain Ownership Agreement. We and Georgia Power have each elected to schedule separately our respective ownership interests. The Rocky Mountain Operating Agreement will terminate in 2035. The Rocky Mountain Ownership and Operating Agreements provide that, should a co-owner fail to make any payment when due, among other things, such non-paying co-owner's rights to output of capacity and energy or to exercise any other right of a co-owner would be suspended until all amounts due, with interest, had been paid. The capacity and energy of a non-paying co-owner may be purchased by a paying co-owner or sold to a third party.

ITEM 3. LEGAL PROCEEDINGS

On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost-sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power’s related financial obligations. Based on the current project budget and Georgia Power’s interpretation of the Global Amendments, our project budget would be $8.65 billion, and we would incur approximately $530 million of additional construction costs (excluding related financing costs) and we would retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

The ultimate outcome of pending litigation against us cannot be predicted at this time; however, we do not anticipate that the ultimate liabilities, if any, arising from such proceedings would have a material effect on our financial condition or results of operations. For information about loss contingencies, including litigation related to Plant Scherer, of which we are a co-owner, that could have an effect on us, see Note 12 of Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Not applicable.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial and statistical data. The financial data presented as of the end of and for each year in the three-year period ended December 31, 2022, has been derived from our consolidated audited financial statements. This data should be read in conjunction with "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" and the "FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA."

	(dollars in thousands)		
	2022	2021	2020
STATEMENTS OF REVENUES AND EXPENSES DATA			
Operating revenues:			
Sales to members	**$ 1,974,683**	$ 1,557,109	$ 1,377,010
Sales to non-members	**155,454**	47,754	608
Operating expenses	**$ 1,936,086**	$ 1,410,482	$ 1,159,909
Other income, net	**$ 72,244**	$ 71,254	$ 50,695
Net interest charges	**$ 204,591**	$ 207,854	$ 212,509
Net margin	**$ 61,704**	$ 57,781	$ 55,895
BALANCE SHEET DATA			
Assets:			
Total electric plant	**$ 12,490,108**	$ 11,757,327	$ 10,870,857
Total assets	**$ 16,489,370**	$ 15,707,026	$ 14,240,156
Capitalization:			
Patronage capital and membership fees	**$ 1,192,127**	$ 1,130,423	$ 1,072,642
Long-term debt and obligations under finance leases	**12,001,694**	10,983,930	10,695,475
Obligation under Rocky Mountain transactions	**27,945**	26,151	24,473
Other	**2,256**	1,550	2,388
Total long-term debt and equities	**$ 13,224,022**	$ 12,142,054	$ 11,794,978
Less: Long-term debt and finance leases due within one year	**322,102**	281,238	208,649
Less: Unamortized debt issuance costs and bond discounts	**114,142**	111,909	119,565
Total capitalization	**$ 12,787,778**	$ 11,748,907	$ 11,466,764
OTHER DATA			
Megawatt hours sold to members	**25,634,984**	24,727,585	22,187,311
Member revenues per kWh sold	**7.70 ¢**	6.30 ¢	6.21 ¢
Equity Ratio[1]	**9.0 %**	9.3 %	9.1 %
Margins for Interest Ratio[2]	**1.14**	1.14	1.14

(1) Our equity ratio is calculated, pursuant to our first mortgage indenture, by dividing patronage capital and membership fees by total capitalization plus unamortized debt issuance costs and bond discounts and long-term debt and finance leases due within one year ("Total long-term debt and equities" in the table above). We have no financial covenant that requires us to maintain a minimum equity ratio; however, a covenant in the first mortgage indenture restricts distributions of equity (patronage capital) to our members if our equity ratio is below 20%. We also have covenants in certain of our line of credit agreements that currently require us to maintain minimum total patronage capital of $750 million.

(2) Our margins for interest ratio is calculated on an annual basis by dividing our margins for interest by interest charges, both as defined in our first mortgage indenture. The first mortgage indenture obligates us to establish and collect rates that, subject to any necessary regulatory approvals, are reasonably expected to yield a margins for interest ratio equal to at least 1.10 for each fiscal year. In addition, the first mortgage indenture requires us to demonstrate that we have met this requirement for certain historical periods as a condition to issuing additional obligations under the first mortgage indenture. For 2023, our board of directors approved a budget to achieve a 1.14 margins for interest ratio, above the minimum 1.10 ratio required by the first mortgage indenture. As our capital requirements continue to evolve, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Overview

General

Our principal business is reliably providing wholesale electric service to our 38 members in a safe and cost-effective manner. Consequently, substantially all of our revenues and cash flow are derived from sales to our members pursuant to take-or-pay wholesale power contracts that extend through 2050. These contracts obligate our members jointly and severally to pay all of our costs and expenses associated with owning and operating our power supply business. To that end, our rate structure provides for a pass-through of actual energy costs. Charges for fixed costs, including capacity, other non-energy charges, debt service obligations and the margin required to meet our budgeted margins for interest ratio are carefully managed throughout the year to ensure that we collect sufficient capacity-related revenues. Our rate structure provides us with the ability to manage our revenues to assure full recovery of our costs and has enabled us consistently to meet our financial obligations since our formation in 1974.

2022 Financial Results

We had another successful year in 2022 and continue to be well positioned, both financially and operationally, to fulfill our obligations to our members, bondholders and creditors. Our revenues were more than sufficient to recover all of our costs and to satisfy all of our debt service obligations and financial covenants. Specifically, we recorded a net margin of $61.7 million in 2022, which achieved the 1.14 margins for interest ratio approved by our board of directors and exceeded the 1.10 margins for interest ratio required to meet the rate covenant under our first mortgage indenture. For 2023, we are again targeting a margins for interest ratio of 1.14, effectively increasing our annual margins by 40% over the minimum required level. We anticipate that we will continue to target a 1.14 margins for interest ratio through the remainder of the Vogtle Units No. 3 and No. 4 construction period.

As a result of expanding our portfolio of generation resources through the construction of Vogtle Units No. 3 and No. 4 and the acquisition of multiple natural gas-fired generation resources and the upgrading of our generation facilities, our total assets and total debt have significantly increased over the past several years. At December 31, 2022, our total assets were $16.5 billion and total long-term debt was $11.9 billion. During the remainder of the Vogtle construction period, we expect that our assets and long-term debt will continue to increase. Despite a rising interest rate environment for much of 2022, strategic financing and refinancing of capital investments with long-term debt through the Department of Energy and Rural Utilities Service loan guarantee programs, taxable and tax-exempt capital markets offerings enabled us to borrow long-term debt at relatively low rates and our weighted average interest cost on long-term debt was 3.78% per annum at December 31, 2022. We will continue to actively manage our debt portfolio and utilize advantageous borrowing programs available to us as our ability to borrow at lower costs ultimately benefits our members and their customers as interest savings are reflected in our pass-through rate structure.

Due to increased fuel prices as well as increased member and non-member demand, our revenues exceeded $2 billion for the first time with total operating revenue of $2.1 billion for the year ended December 31, 2022. This represented a 33% and 55% increase, respectively, over total operating revenue of $1.6 billion in 2021 and $1.3 billion in 2020. Our cost-plus formulary rate structure ensures recovery of these increased fuel costs on a monthly basis; however, we remain focused on delivering cost-effective, reliable power to our members and continue to seek ways to mitigate the impact of these cost increases on our members. Our continued investment in new resources, including Vogtle Units No. 3 and No. 4, is intended to provide long-term cost-effective and reliable power that is less sensitive to market volatility.

Vogtle Units No. 3 and No. 4

The construction of Vogtle Units No. 3 and No. 4 continues to be a primary focus area. As of December 31, 2022, our total investment in the additional Vogtle units was approximately $8.0 billion.

Southern Nuclear and Georgia Power continue to manage the construction at the site and the project reached a number of important milestones during 2022 and early 2023. Following the Nuclear Regulatory Commission publishing its 103(g) finding that the Unit No. 3 acceptance criteria in the combined license had been met, nuclear fuel was loaded in October 2022 and Unit No. 3 reached initial criticality in March 2023. Unit No. 3 is proceeding through remaining start-up and pre-operational testing activities. Unit No. 4 has transitioned into component and system testing activities and successfully completed cold-hydro testing in December 2022 and commenced hot functional testing in March 2023. However, progress at the project has been slowed by challenges related to construction productivity, construction remediation work, the pace of system turnovers, the timeframe and duration of testing, incomplete documentation, including inspection reports. Over the course of 2022 and early 2023, these challenges continued to impact the project budget and schedule and our current anticipated in-service dates are now June 2023 and March 2024, respectively.

Our current budget, which includes capital costs, allowance for funds used during construction and some level of contingency is $8.1 billion. This budget reflects our June 2022 exercise of the tender option in the Global Amendments to the Joint Ownership Agreements. Based on the current project budget and our interpretation of the Global Amendments, we would transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share in the additional units would decline from 30% to approximately 27.5%.

In connection with the September 2018 vote to continue construction at the Vogtle project, Georgia Power entered into a binding term sheet to mitigate certain financial exposure for the other Co-owners. In February 2019, all of the Co-owners entered into the Global Amendments to the Joint Ownership Agreements to memorialize the provisions of the term sheet. The Global Amendments include both a cost-sharing provision and a tender option. The cost-sharing provision provides that, in the event of specified budget increases, Georgia Power will assume a greater responsibility for certain construction costs which would save us up to $99 million of construction costs. The tender option allows each of the Co-owners, other than Georgia Power, to cap their capital costs by tendering a portion of their ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Co-owner's remaining share of construction costs in excess of the estimate at completion in the VCM 19 report plus $2.1 billion. As the VCM 19 total project cost is $17.1 billion (which excludes non-shareable costs), we believe that certain thresholds related to both the cost-sharing provisions and tender option have been crossed and that those financial exposure mitigants are available to us. We and Georgia Power do not agree as to the applicable dollar thresholds for either the cost-sharing provisions or tender option and have commenced litigation to resolve these disputes.

Despite these challenges, we remain committed to the Vogtle project and look forward to the commercial operation of Units No. 3 and No. 4. Upon completion, Vogtle Units No. 3 and No. 4 will have an aggregate of approximately 2,200 megawatts of carbon-free, baseload generating capacity. We expect our interest in these units to be valuable assets for us and our members over the next 60 to 80 years and to contribute to our diverse pool of generation resources. For additional information regarding Vogtle Units No. 3 and No. 4 and related financing activities, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*," "– Financial Condition – *Financing Activities – Department of Energy-Guaranteed Loans*" and "– *Capital Requirements – Capital Expenditures*" and Note 7a of Notes to Consolidated Financial Statements.

Liquidity Position

Our strong liquidity position continues to be one of the most positive attributes contributing to our solid financial standing. This liquidity is comprised of a diversified, cost-effective mix of cash (including short-term investments), committed lines of credit and commercial paper. Our primary source of liquidity is a $1.2 billion unsecured credit facility that extends through December 2024 and supports our commercial paper program. Additionally, we have three other bank credit facilities which provide another $600 million in credit commitments.

In addition to our strong liquidity, we have multiple sources of long-term financing available to meet our anticipated capital needs. These sources include the Rural Utilities Service federal loan program and the taxable and tax-exempt capital markets. We expect to continue utilizing each of these sources of capital to meet our long-term financing needs in the coming years. In December 2022, we completed our borrowing under the Department of Energy loan program and have borrowed an aggregate of over $4.6 billion to finance the construction of the new Vogtle Units.

With our current sources of committed short-term and long-term funding, we anticipate that we will have sufficient liquidity to complete Vogtle Units No. 3 and No. 4.

Environmental Regulations

Another of our key focus areas is maintaining compliance with all applicable environmental laws and regulatory standards. We own electric generation facilities powered by nuclear, natural gas, coal and hydro resources which presents substantial challenges for us and our members to comply with existing environmental regulations. Based on the President's executive orders and on statements and proposed rules from federal administrative agencies, we expect several existing environmental regulations to become more stringent. As an electric cooperative that operates on a not-for-profit basis, our compliance costs are ultimately borne by our members' electricity consumers.

Greenhouse gas emissions, particularly carbon dioxide, are the focus of some of the anticipated federal environmental regulations. Effective February 19, 2021, the United States rejoined the Paris Climate Agreement and, in accordance with the agreement, subsequently proposed economy-wide carbon dioxide reductions of 50-52% of 2005 levels by 2030. In order to meet this economy-wide goal, analyses indicate that the power sector would have to reduce carbon dioxide emissions by approximately 80% below 2005 levels by 2030. Additionally, the EPA is expected to release a new rule in 2023 to address carbon dioxide emissions from existing power plants that will likely be more stringent than the Affordable Clean Energy (ACE) rule. At this time, we cannot predict the outcome or potential cost of any legislative or regulatory changes on us or our members but such costs could be significant.

We believe that we are well-situated to effectively manage such challenges and that our diverse asset base, along with our investment in additional carbon-free generation at Vogtle Units No. 3 and No. 4 and recent additions of natural gas generation resources, positions us well to continue to meet our members' needs. Further, our members continue to pursue renewable generation opportunities and invest where they deem appropriate in order to further diversify their power supply resources to meet the demands of their member consumers and prepare for potential future limitations on greenhouse gas emissions.

In addition to greenhouse gases, we must also comply with several other environmental regulations. For example, in order to comply with federal and state coal combustion residual rules and effluent limitation guidelines, we are investing approximately $300 million in capital costs, of which $250 million has already been spent, in addition to the current projection of $550 million to $700 million (in year of expenditure dollars) associated with our corresponding asset retirement obligations. If existing laws or regulations related to the disposal of CCR and treatment of coal ash ponds were to change or we are otherwise required to revise our existing closure plans, our related obligations could increase materially.

Changes to Our Generation Portfolio

In 2021, we acquired the Effingham combined cycle energy facility, which added approximately 500 megawatts to our generating portfolio. In December 2022, we acquired two combustion turbine units at the Washington County Power Facility with a nominal capacity of 322 megawatts. These additional facilities will help us to serve the expanding needs of our members. Offsetting a portion of these additions was the early retirement of Plant Wansley, of which we owned a 30% interest (approximately 500 megawatts), in August 2022.

Following passage of the Inflation Reduction Act in 2022, we and our members are evaluating new incentives available to us to further diversify our generation portfolio through the addition of new battery storage and renewable generation resources. We are also in the process of upgrading the two units at Washington County and four units at our Talbot Energy Facility for dual fuel capabilities that will further enhance our generation portfolio's winter resiliency and strengthen our ability to serve the needs of our members.

Focus on ESG

In October 2022, we released our second environmental, social and corporate governance (ESG) report highlighting our and our members' efforts in these areas as well as several recent achievements. We and our members have been working toward a cleaner energy path for many years. We are committed to making strides toward improving the environment through reducing greenhouse gas emissions, including carbon. With respect to carbon, by 2025, after Vogtle Units No. 3 and No. 4 come on-line, we are forecasting that our carbon emissions intensity per megawatt-hour will decline 56% from 2005 levels.

We supply nearly 60% of our members' energy requirements from our diverse portfolio of nuclear, gas, coal and hydro resources. Green Power EMC, owned by our members and supported by Oglethorpe employees, specializes in the purchase of renewable energy for the members. Green Power currently purchases 584 megawatts of renewable energy resources and is expected to grow to more than 836 megawatts by 2025. Our members also contract directly with renewable suppliers, and by the end of 2023 we anticipate that the members' total solar portfolio will exceed 1,500 megawatts.

We are also proud of our work in the social and governance areas of ESG. Electric cooperatives were created to bring electricity to underserved, rural areas and continue that mission today as our members serve many of the most economically disadvantaged areas of Georgia. As a not-for-profit cooperative, owned and governed by our members, we have a unique perspective on ESG considerations. We were created by and exist to serve our members and our focus on members is part of who we are. More specifically, our members elect our board of directors and our equity is our members' patronage capital. The critical role our members play in our business is reflected in the seven pillars of cooperative organizations: (i) voluntary and open membership, (ii) democratic member control, (iii) members' economic participation, (iv) autonomy and independence, (v) education, training and information, (vi) cooperation among cooperatives and (vii) concern for community.

We embrace diversity in the workplace. Of our executive level officers, over half are women. Of our entire workforce, 19% are minorities and 21% are military veterans. We have established a culture of high ethical and safety standards for our workforce, along with the robust risk management and strategic planning processes to guide us through the transitioning energy landscape.

We are proud of our progress in a number of ESG-related areas and continue to push ourselves to improve in these areas. Our commitment to these goals goes beyond talking points. For several years, certain of the corporate goals that determine our executives' performance pay have been, and continue to be, directly related to environmental, worker safety and corporate governance metrics.

Outlook for 2023

As the electric utility industry across the country continues to experience change, we remain focused on providing reliable, safe, and cost-effective energy to our members and the 4.4 million people they serve. We believe we are well positioned to do so. As discussed above, there are certain risks and challenges that we must continue to address, most notably related to Vogtle Units No. 3 and No. 4 and anticipated environmental regulation. However, as we manage our risks, we intend to keep doing what we have done so successfully for the last 49 years, including, among other things:

- maintaining a balanced and diverse portfolio of generating resources, including nuclear, natural gas, coal and hydro and continuing the reliable, efficient and cost-effective operation of these resources;

- maintaining strong liquidity to fulfill current obligations and to finance future capital expenditures; and

- working with our members to explore existing and emerging opportunities to add value to our ultimate consumers.

Accounting Policies

Basis of Accounting

We follow generally accepted accounting principles in the United States and the practices prescribed in the Uniform System of Accounts of the Federal Energy Regulatory Commission as modified and adopted by the Rural Utilities Service.

Critical Accounting Policies

We have determined that the following accounting policies are critical to understanding and evaluating our financial condition and results of operations and requires our management to make estimates and assumptions about matters that were uncertain at the time of the preparation of our financial statements. Changes in these estimates and assumptions by our management could materially impact our results of operations and financial condition. Our management has discussed these critical accounting policies and the related estimates and assumptions with the audit committee of our board of directors.

Regulatory Accounting. We are subject to the provisions of the Financial Accounting Standards Board (FASB) authoritative guidance issued regarding regulated operations. The guidance permits us to record regulatory assets and regulatory liabilities to reflect future cost recoveries or refunds, respectively, that we have a right to pass through to our members. At December 31, 2022, our regulatory assets and regulatory liabilities totaled $1.2 billion and $792.2 million, respectively. While we do not currently foresee any events such as competition or other factors that would make it not probable that we will recover these costs from our members as future revenues through rates under our wholesale power contracts, if such an event were to occur, we could no longer apply the provisions of accounting for regulated operations, which would require us to eliminate all regulatory assets and regulatory liabilities that had been recognized as a charge or credit to our statement of revenues and expenses and begin recognizing assets and liabilities in a manner similar to other businesses in general. In addition, we would be required to determine any impairment to other assets, including plants, and write-down those assets, if impaired, to their fair values.

Asset Retirement Obligations. Accounting for asset retirement and environmental obligations requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Estimating the amount and timing of future expenditures includes, among other things, making projections of when assets will be retired and ultimately decommissioned, the amount of decommissioning costs, and how costs will escalate with inflation.

A significant portion of our asset retirement obligations relates to our share of the future cost to decommission our operating nuclear units and the coal ash ponds at our coal-fired units. At December 31, 2022, our nuclear decommissioning and coal ash related asset retirement obligations were $820.1 million and $461.5 million, respectively. Our asset retirement obligations represent an estimate of the present value of anticipated retirement costs. For additional detail regarding our asset retirement obligations, see Note 1h of Notes to Consolidated Financial Statements. These obligations represented 95% of our total asset retirement obligations.

Given its significance, we consider our nuclear decommissioning liabilities critical estimates. Approximately every three years, new decommissioning studies for Plants Hatch and Vogtle are performed. These studies provide us with periodic site-specific "base year" cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for the plants. These cost studies are based on relevant information available at the time they are performed; however, estimates of the amount and timing of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual costs. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation and discount rates, which we consider to be critical assumptions. Our current estimates are based upon studies that were performed in 2021. For ratemaking purposes, we record decommissioning costs over the expected service life of each unit. The impact on measurements of asset retirement obligations using different assumptions in the future may be significant.

We also consider our coal ash related decommissioning liabilities at Plants Scherer and Wansley to be critical estimates, in particular those for the coal ash ponds. Cost studies are periodically performed to provide site-specific "base year" estimates that determine the nature and timing of planned decommissioning costs. These cost studies are based on relevant information available at the time they are performed; however, estimates of the amount and timing of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual costs. Critical assumptions include coal ash pond closure strategy, including water treatment requirements, and the volume of coal ash in the ponds. In addition, these estimates are dependent on other subjective factors, such as estimates of costs to perform the decommissioning and post-closure activities, timing of expenditures, and the selection of cost escalation and discount rates. Our current estimates are based upon studies that were performed in 2022. For ratemaking purposes, we are applying regulated operations accounting to the decommissioning costs and currently expect to recover ash pond closure costs over approximately 16 years. The impact on measurements of asset retirement obligations using different assumptions in the future may be significant.

Summary of Cooperative Operations

Sources of Revenues

We operate on a not-for-profit basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to establish reasonable reserves and meet certain financial coverage requirements. Our primary source of revenue is the sale of capacity and energy to our members for a portion of their energy requirements. We may also sell capacity and energy to non-members. Capacity revenues are the revenues we receive for providing electric service whether or not our generation and purchased power resources are dispatched to produce electricity. Energy revenues are the revenues we receive by selling electricity that we generate or purchase.

We have assigned fixed percentage capacity cost responsibilities to our members for all of our generation and purchased power resources. Each member has contractually agreed to pay us for the electric capacity assigned to it based on its individual fixed percentage capacity cost responsibility.

Each member is also contractually obligated to pay us for electric energy we provide to it based on individual usage. Energy sales to our members fluctuate from period to period based on several factors, including fuel costs, weather and other seasonal factors, load requirements in the service territories of our members, operating costs, availability of electric generation resources and our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights. In addition, as we do not provide our members with all of their energy requirements, energy sales may also fluctuate based on our members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers.

Formulary Rate

The rates we charge our members are designed to cover all of our costs plus a margin. This cost-plus rate structure is set forth as a formula in the rate schedule to the wholesale power contracts between us and each of our members. These contracts require us to design capacity and energy rates that generate revenues sufficient to recover all costs, including payments of principal and interest on our indebtedness, to establish and maintain reasonable margins and to meet the financial coverage requirements under the first mortgage indenture.

The formulary rate provides for the pass through of our fixed costs to members as capacity charges and our variable costs to members as energy charges. Fixed costs are assigned to members according to their individual fixed percentage capacity cost responsibility for each resource in which they participate. Variable costs are passed through to our members based on the amount of energy supplied to each member.

Capacity charges are based on an annual budget of fixed costs plus a targeted margin and are billed to members in equal monthly installments over the course of the year. Fixed costs include items such as depreciation, interest, fixed operations and maintenance expenses, administrative and general expenses. We monitor fixed cost budget variances to projected actual costs throughout the year, and with board approval, make budget adjustments when and as necessary to ensure that we generate revenues sufficient to recover all costs and to meet our targeted margin. Budget adjustments are typically made twice a year; once during the first quarter and again at year end. In contrast to the way we bill our members for capacity charges, which are billed based on a budget and trued up to actuals by the end of the year, energy charges are billed on a more real-time basis. Estimated energy charges are billed to members based on the amount of energy supplied to each member during the month, and are adjusted when actual costs are available, generally the following month. Energy charges, or variable costs, include fuel, purchased energy and variable operations and maintenance expenses. Each generating resource has a different variable cost profile, and members are billed based on the energy cost profile of the resources from which their energy is supplied.

Margins

Revenues in excess of current period costs in any year are designated as net margin in our statements of revenues and expenses and we have generated a positive net margin every year since our formation in 1974. Under our first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates that are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. See "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture" for a discussion of how we calculate our margins for interest ratio.

In the event we were to fall short of the minimum 1.10 margins for interest ratio at year end, the formulary rate is designed to recover the shortfall from our members in the following year without any additional action by our board of directors.

Prior to 2009, we budgeted and achieved annual margins for interest ratios of 1.10, the minimum required by the first mortgage indenture. To enhance margin coverage during a period of increased capital requirements, our board of directors has approved budgets with margins for interest ratios that exceeded 1.10. Since 2010, we have achieved our board approved margins for interest ratio of 1.14, and our board has approved a margins for interest ratio of 1.14 for 2023. As our capital requirements continue to evolve, our board will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

Patronage Capital

Retained net margins are designated on our balance sheets as patronage capital. As a cooperative, patronage capital constitutes our principal equity. As of December 31, 2022, we had $1.2 billion in patronage capital and membership fees. Our equity ratio, calculated pursuant to our first mortgage indenture as patronage capital and membership fees divided by total capitalization and long-term debt due within one year, was 9.0% and 9.3% at December 31, 2022 and 2021, respectively.

Patronage capital is allocated to each of our members on the basis of their fixed percentage capacity responsibilities in our generation resources. Any distribution of patronage capital is subject to the discretion of our board of directors and limitations under our first mortgage indenture. See "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture" for a discussion regarding limitations on distributions under our first mortgage indenture.

Rate Regulation

Under our loan agreements with each of the Rural Utilities Service and Department of Energy, changes to our rates resulting from adjustments in our annual budget are generally not subject to their approval. We must provide the Rural Utilities Service and Department of Energy with a notice of and opportunity to object to most changes to the formulary rate under the wholesale power contracts. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders." Currently, our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

Tax Status

While we are a not-for-profit membership corporation formed under the laws of Georgia, we are subject to federal and state income taxation. As a taxable cooperative, we are allowed to deduct patronage dividends that we allocate to our members for purposes of calculating our taxable income. We annually allocate income and deductions between patronage and non-patronage activities and substantially all of our income is from patronage-sourced activities, resulting in no current period income tax expense or current income tax liability. For further discussion of our taxable status, see Note 5 of Notes to Consolidated Financial Statements.

Results of Operations

Factors Affecting Results

Certain of our recent financial and operational results were affected both by the way in which we dispatch our power plants as well as by significant events or trends described below.

The types of generation assets we own include several natural gas-fired simple cycle combustion turbine plants, three combined cycle natural gas-fired plants, a plant that burns sub-bituminous coal, two nuclear plants and a pumped storage hydroelectric plant. Plant Wansley, a plant that burned bituminous coal, was retired on August 31, 2022.

In 2022, we acquired two of the four combustion turbine natural gas-fired units at the Washington County Power Plant, adding to our already diverse mix of generation and fuel types among our power plants. See Note 14 of Notes to Consolidated Financial Statements for additional information regarding this acquisition.

Decisions to dispatch our power plants and thus the amount of energy we generate and sell to our members are economically driven by supply and demand considerations. The primary supply considerations include (i) fuel prices and other marginal operating costs of the plant, which factor into a dispatch cost we calculate for each resource, (ii) plant availability, which is driven by factors such as outages for maintenance or refuelings and (iii) plant efficiency, as determined by the heat rate which measures the amount of fuel required to generate one kilowatt hour of electricity. We prioritize the order in which we typically dispatch our plants such that we dispatch our available plants with the lowest dispatch cost first, and those with the highest dispatch cost last, when demand is highest.

The primary demand consideration that affects how we dispatch our plants is the amount of energy our members require from us. This is a function of weather, economic activity, residential use patterns and the relative cost and availability of our members' third party supply arrangements, which account for a significant portion of the energy they purchase.

Our energy sales to members also fluctuate from period to period based on weather and, in 2022, weather was a significant factor. The 2022 summer experienced extremely hot weather during the last half of June that led to a new all-time peak demand for our members at that time. The month of December experienced extremely cold weather during the Christmas holiday weekend which surpassed the earlier all-time peak. This weather resulted in increased member energy requirements compared to 2021 and 2020. As a result, the amount of energy (in megawatts) we generated and sold to members was higher than in 2021 and 2020.

Since we pass through all of our costs to members, including fuel cost, which is our most significant operating cost, the cost of our energy sales to our members as well as our member sales (in dollars) is significantly affected by fuel prices. The price of natural gas is the most significant variable in our cost of fuel and also affects how we dispatch our generation resources. In both 2022 and 2021, natural gas prices increased significantly compared with each of the previous years due to market pressures on supply and demand compared to relatively low prices in recent years. Coupled with the increased member sales (in megawatts), the increased natural gas prices resulted in higher cost of fuel and member sales (in dollars) in each year. Due to increases in natural gas prices, our coal units were also more economical resulting in more coal generated energy to sell to our members in 2022 than in 2021 and 2020.

In addition to the prevailing market price, our average cost of natural gas per kilowatt hour generated is also affected by how efficiently our natural gas facilities burn the gas. Compared to our combined cycle units, our combustion turbine units are less efficient and thus burn more gas per kilowatt hour of electricity generated. Consequently, our combustion turbine units have a higher dispatch cost than our combined cycle units and are typically used to generate energy only during periods of higher electricity demand, such as on hot summer days or colder winter days. The more extreme weather in 2022 resulted in significantly higher generation from our combustion turbine units compared to 2021 and 2020 and this also contributed to a higher cost of fuel and member sales (in dollars) in 2022 than in 2021 and 2020.

Combined cycle generation was slightly higher in 2022 compared to 2021 as a result of the Effingham acquisition in mid-2021. The majority of the Effingham generation was used to serve off-system sales on behalf of the members who are currently deferring their portion of the output of the facility. This also resulted in a significant increase in sales to non-members compared to 2021 and 2020.

Our nuclear units require refueling on an 18 or 24-month cycle and these refueling outages, which typically last several weeks, resulted in fluctuations in nuclear plant availability and generation in each of the last three years. These shutdowns and outages significantly reduced generation at the affected plants, reduced kilowatt-hour sales to and energy revenues from our members during the periods that the plants were not generating power.

We also continued to make significant capital expenditures over the past three years, particularly for the new units under construction at Plant Vogtle and the Effingham and Washington County acquisitions, which we have primarily financed with debt. These financings have increased our overall debt which has increased our interest expense and our allowance for debt funds used during construction. Additionally, since our margin is calculated as a percentage of our secured interest expense, our net margin has generally increased. As discussed under "– Financial Condition – *Capital Resources – Capital Expenditures*," we expect significant capital expenditures to continue through the completion of the additional units at Plant Vogtle.

Net Margin

Our net margin for the years ended December 31, 2022, 2021 and 2020 was $61.7 million, $57.8 million and $55.9 million, respectively. These amounts produced a margins for interest ratio of 1.14 in each of 2022, 2021 and 2020. For additional information on our margin requirement, see "– Summary of Cooperative Operations – *Rate Regulation."*

Operating Revenues

Sales to members. We generate revenues principally from the sale of electric capacity and energy to our members. Capacity revenues are the revenues we receive for electric service whether or not our generation and purchased power resources are dispatched to produce electricity. These revenues are designed to recover the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges, plus a targeted margin. Energy revenues are the sales of electricity generated or purchased for our members. Energy revenues recover the variable costs of our business, including fuel, purchased energy and variable operation and maintenance expense.

The components of member revenues were as follows:

		(in thousands)		2022 vs. 2021	2021 vs. 2020
	2022	2021	2020	% Change	% Change
Capacity revenues	**$ 984,036**	$ 946,662	$ 971,071	3.9 %	(2.5)%
Energy revenues	**990,647**	610,447	405,939	62.3 %	50.4 %
Total	**$ 1,974,683**	$ 1,557,109	$ 1,377,010	26.8 %	13.1 %
kWh Sales to members	**25,634,984**	24,727,585	22,187,311	3.7 %	11.4 %
Cents/kWh	**7.70**	6.30	6.21	22.3 %	1.5 %
Member energy requirements supplied	**58 %**	62 %	57 %	(6.5)%	8.8 %

Capacity revenues increased in 2022 compared to 2021 due to the recovery of higher fixed production maintenance costs. The slight decrease in capacity revenues in 2021 compared to 2020 was due primarily to the recovery of lower fixed production maintenance costs. For a discussion of production costs and depreciation expense, see "– *Operating Expenses.*"

The 62.3% increase in energy revenues from members in 2022 compared to 2021 was primarily a result of an increase in total fuel expense, including a 3.7% increase in generation for member sales. Energy revenues from members in 2021 compared to 2020 increased 50.4% due to an 11.4% increase in total fuel expense, including an increase in generation for member sales. For a discussion of fuel expense, see "– *Operating Expenses*."

Sales to non-members. In 2022, energy revenues from non-members were primarily from the sale of the Effingham deferring members' output into the wholesale market. In 2022, we recognized capacity revenues from non-members relating to our Washington County acquisition. For additional information regarding the Washington County acquisition, see Note 14 of Notes to Consolidated Financial Statements.

Sales to non-members were as follows:

		(in thousands)	
	2022	2021	2020
Energy revenues	**$ 155,372**	$ 47,754	$ 608
Capacity revenues	**$ 82**	$ —	$ —
kWh Sales to non-members	**1,690,454**	1,039,957	30,133
Cents/kWh	**9.19**	4.59	2.02

Operating Expenses

Our operating expenses increased 37.3% in 2022 compared to 2021 primarily due to significantly higher fuel costs as well as increased production costs. In 2021 compared to 2020, operating expenses increased 21.6% primarily due to an increase in fuel costs and depreciation and amortization expense offset by a decrease in production costs.

The following table summarizes our fuel costs and net kilowatt-hour (kWh) generation by generating source.

	Cost (dollars in thousands)					Generation (kWh in thousands)					Cents per kWh				
Fuel Source	**2022**	2021	2020	2022 vs. 2021 % Change	2021 vs. 2020 % Change	**2022**	2021	2020	2022 vs. 2021 % Change	2021 vs. 2020 % Change	**2022**	2021	2020	2022 vs. 2021 % Change	2021 vs. 2020 % Change
Coal	**$ 107,207**	$ 86,289	$ 40,222	24.2 %	114.5 %	**2,856,494**	2,559,235	1,137,027	11.6 %	125.1 %	**3.75**	3.37	3.54	11.3 %	(4.8)%
Nuclear	**73,871**	77,366	75,968	(4.5)%	1.8 %	**10,206,060**	10,171,948	9,832,564	0.3 %	3.5 %	**0.72**	0.76	0.77	(4.8)%	(1.3)%
Natural Gas:															
Combined Cycle	**704,809**	387,069	202,030	82.1 %	91.6 %	**13,100,271**	12,722,401	10,473,139	3.0 %	21.5 %	**5.38**	3.04	1.93	76.8 %	57.5 %
Combustion Turbine	**159,202**	48,272	42,034	229.8 %	14.8 %	**1,824,570**	1,026,430	1,386,569	77.8 %	(26.0)%	**8.73**	4.70	3.03	85.5 %	55.1 %
	$1,045,089	$598,996	$360,254	74.5 %	66.3 %	**27,987,395**	26,480,014	22,829,299	5.7 %	16.0 %	**3.73**	2.26	1.58	65.1 %	43.0 %

Fuel

Total fuel expense increased in 2022 compared to 2021 primarily as a result of an increase in the average cost of fuel and an increase in generation for members and non-members. The increase in average fuel cost was primarily due to higher average natural gas prices in 2022. The overall increase in generation in 2022 compared to 2021 was largely due to increases in sales to our members as a result of weather events and sales to non-members from Effingham. In 2022 and 2021, $115.0 million and $30.0 million of net gains recognized, respectively, were included in total fuel expense for the settlement of natural gas financial contracts we utilize to manage our exposure to fluctuations in market prices. Total fuel expense increased in 2021 compared to 2020 primarily as a result of higher natural gas prices, which also contributed to increased generation from coal-fired plants as those plants became more economical. Total generation increased significantly in 2021 compared to 2020 largely due to members obtaining more of their energy requirements from us rather than their third party suppliers and generation output from Effingham that was primarily sold to our non-members.

Production

Production costs can vary due to the number and extent of outages in a given year. Production costs increased 14.1% in 2022 compared to 2021 and decreased 4.0% in 2021 compared to 2020. The increase in 2022 was due to more costly planned major maintenance outages and the result of deferring Effingham's effects on net margin during 2022 compared to 2021. The decrease in 2021 was due to less costly planned major maintenance outages.

Depreciation and amortization

Depreciation and amortization expense increased in 2022 compared to 2021 primarily as a result of higher depreciation rates that went into effect in 2022, as well as the addition of Effingham which was acquired in 2021.

Other Income

Total other income was relatively unchanged in 2022 compared to 2021. The 40.6% increase in other income in 2021 compared to 2020 was primarily due to gains recognized on the sale of spare parts.

Interest Charges

Allowance for debt funds used during construction increased in 2022 and 2021 primarily due to increased borrowings for Vogtle Units No. 3 and No. 4 construction expenditures.

Financial Condition

Overview

Consistent with our budgeted margin for 2022, we achieved a 1.14 margins for interest ratio which produced a net margin of $61.7 million. This net margin increased our total patronage capital (our equity) and membership fees to $1.2 billion at December 31, 2022. Our 2023 budget again targets a 1.14 margins for interest ratio.

Our equity to total capitalization ratio, as defined in our first mortgage indenture, was 9.0% at December 31, 2022 and 9.3% at December 31, 2021. We anticipate that our equity ratio will remain around its current level during the remainder of the Vogtle construction period; however, the absolute level of patronage capital will continue to increase.

We had a strong liquidity position at December 31, 2022 with $1.7 billion of unrestricted available liquidity, including $595.4 million of cash and cash equivalents. We issued commercial paper throughout the year to provide interim financing for the Plant Vogtle construction, the Washington County acquisition and for other general purposes. The average cost of funds on the $655.7 million of commercial paper outstanding at December 31, 2022 was 4.8%.

Electric plant in service decreased in 2022 primarily due to the retirement of Plant Wansley in August 2022. However, our total assets increased to $16.5 billion at December 31, 2022 from $15.7 billion at December 31, 2021 due to $1.2 billion of property additions. These additions include costs related to the construction of the new Vogtle units, the Washington County acquisition, normal additions and replacements to existing generation facilities and purchases of nuclear fuel. For the past several years, our total assets have significantly increased primarily due to increases in construction work in progress in connection with the additional nuclear units under construction at Plant Vogtle.

Restricted investments and restricted cash and short-term investments decreased by $217.4 million at December 31, 2022 compared to December 31, 2021. The net decrease was due to the utilization of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account for Rural Utilities Service-guaranteed Federal Financing Bank debt service payments, offset by an increase in restricted cash posted by our counterparties under our natural gas swap agreements. We expect to fully utilize the remaining Rural Utilities Service Cushion of Credit deposits at December 31, 2022 by March 2023.

Regulatory assets increased by $203.5 million at December 31, 2022 compared to December 31, 2021. The net increase was primarily due to the increase in the deferral of accelerated depreciation associated with the early retirement of Plant Wansley, which occurred in August 2022. The increase was also attributable to increases in the deferrals associated with nuclear and coal ash pond asset retirement obligations.

There was a net increase in long-term debt and finance leases of $1.0 billion at December 31, 2022 compared to December 31, 2021. The weighted average interest rate on the $11.9 billion of long-term debt outstanding at December 31, 2022 was 3.78%.

Sources of Capital and Liquidity

Sources of Capital. We fund our capital requirements through a combination of funds generated from operations and short-term and long-term borrowings. See "– *Capital Requirements – Capital Expenditures*" for more detailed information regarding our estimated capital expenditures.

We have $4.6 billion of loans from the Federal Financing Bank that are guaranteed by the Department of Energy to fund a portion of our cost to construct the two new nuclear units at Plant Vogtle. As of December 31, 2022, we had fully borrowed the $4.6 billion of available funds under these loans, of which $4.3 billion was outstanding.

Historically, we have also obtained a substantial portion of our long-term financing from Rural Utilities Service-guaranteed loans funded by the Federal Financing Bank. We continue to utilize these loans for general and environmental improvements, and in 2022 we utilized these loans to provide a portion of the long-term financing for the Effingham acquisition and related costs. We plan to utilize these loans to provide long-term financing for the Washington County acquisition and related costs. However, Rural Utilities Service funding levels for projects we may choose to undertake are uncertain and may be limited in the future due to budgetary and political pressures faced by Congress. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service loans that may be available to us in the future.

We have also issued a substantial amount of taxable and tax-exempt debt in the capital markets. If the Rural Utilities Service loan program were to be curtailed or eliminated, we believe we are well positioned to continue to access capital market financings. See "– *Financing Activities*" for more detailed information regarding our financing plans.

See Note 7 in Notes to Consolidated Financial Statements for additional information regarding these loans.

See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders" for further discussion of our relationship with the Department of Energy and Rural Utilities Service.

Liquidity. At December 31, 2022, we had $1.7 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of $595.4 million of cash and cash equivalents and $1.15 billion of unused and available committed credit arrangements.

Net cash provided by operating activities was $546.3 million in 2022, and averaged $539.4 million per year for the three-year period 2020 through 2022.

At December 31, 2022, we had $1.8 billion of committed credit arrangements in place and $1.15 billion available under four separate credit facilities. These are reflected in the table below:

Committed Credit Facilities

	(dollars in millions)		
	Authorized Amount	**Available 12/31/2022**	**Expiration Date**
Unsecured Facilities:			
Syndicated Line among 12 banks led by CFC	$ 1,210	$ 551 (1)	December 2024
CFC Line of Credit(2)	110	110	December 2023
JPMorgan Chase Line of Credit	350	347 (3)	October 2024
Secured Facilities:			
CFC Term Loan(2)	250	140	December 2023

(1) This facility is dedicated to support outstanding commercial paper and the portion of this facility that was unavailable represents outstanding commercial paper at December 31, 2022.

(2) Any amounts drawn under the $110 million unsecured line of credit with CFC will reduce the amount that can be drawn under the $250 million secured term loan. Therefore, we reflect $140 million as the amount available under the term loan even though there are no amounts outstanding under that facility. Any amounts borrowed under the $250 million term loan would be secured under our first mortgage indenture, with a maturity no later than December 31, 2043.

(3) At December 31, 2022, $2.5 million of this facility was used for letters of credit issued to provide performance assurance to third parties.

We have the flexibility to use the $1.2 billion syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up commercial paper.

Under our commercial paper program, we are authorized to issue commercial paper in amounts that do not exceed the amount of our committed backup lines of credit, thereby providing 100% dedicated support for any commercial paper outstanding. Due to this requirement, any commercial paper we issue will reduce the availability under the $1.2 billion syndicated line of credit. At December 31, 2022, we had issued commercial paper primarily to provide interim funding for:

- payments related to the construction of Vogtle Units No. 3 and No. 4,
- principal payments due under our Department of Energy-guaranteed loans, which began in February 2020 and which we intend to continue funding with commercial paper until Vogtle Unit No. 4 is placed in service, and
- costs related to the Washington County acquisition.

We plan to refinance our commercial paper with long-term debt, either through the issuance of first mortgage bonds, or through financing by the Rural Utilities Service. Rural Utilities Service financing is our preferred source of long-term financing for the Washington County acquisition. See Note 14 of Notes to Consolidated Financial Statements for additional information regarding this acquisition. We intend to issue first mortgage bonds to provide long-term financing of the remaining construction costs for Vogtle Units No. 3 and No. 4, refinancing of the principal payments we are currently paying under our Department of Energy-guaranteed loans and for certain other costs not financed through the Rural Utilities Service.

Our unsecured committed lines of credit permit the issuance of up to $960 million in letters of credit on our behalf, of which $957 million remained available at December 31, 2022. This letter of credit issuance capacity includes $500 million under our $1.2 billion syndicated line of credit, $350 million under our JPMorgan Chase line of credit, and $110 million under our CFC line of credit.

Between projected cash on hand and the credit arrangements currently in place, we believe we have sufficient liquidity to cover normal operations and our interim financing needs, including interim financing for the new Vogtle units, until long-term financing is obtained.

Three of our line of credit facilities contain similar financial covenants that require us to maintain minimum patronage capital levels. Currently, we are required to maintain minimum patronage capital of $750 million. As of December 31, 2022, our patronage capital balance was $1.2 billion. These agreements contain an additional covenant that limits our secured indebtedness and our unsecured indebtedness, both as defined in the credit agreements, to $14 billion and $4 billion, respectively. At December 31, 2022, we had $11.9 billion of secured indebtedness outstanding and $655.7 million of unsecured indebtedness outstanding.

Under our power bill prepayment program, members can prepay their power bills from us at a discount for an agreed number of months in advance, after which point the funds are credited against the participating members' monthly power bills. At December 31, 2022, we had seven members participating in the program and a balance of $108.3 million remaining to be applied against future power bills.

In addition to unrestricted available liquidity, at December 31, 2022 we had $74.0 million of restricted liquidity in connection with deposits made into a Rural Utilities Service Cushion of Credit Account. The Farm Bill passed by Congress in December 2018 modified the Cushion of Credit program. For the period from January 1, 2021 to September 30, 2021, deposits earned interest at 4% per annum. Beginning October 1, 2021, the rate was set at the 1-year floating treasury rate, which was 0.09% per annum, and resets annually on October 1 of each year thereafter. On October 1, 2022, the rate was reset at the 1-year floating treasury rate, which was 4.05% per annum. The program no longer allows additional funds to be deposited into the account. Funds in the account, including interest thereon, can only be applied to debt service on Rural Utilities Service-guaranteed Federal Financing Bank notes. We expect to apply the remaining funds in the Cushion of Credit account by March 2023.

Liquidity Covenants. At December 31, 2022, we had only one financial agreement in place containing a liquidity covenant. This covenant is in connection with the Rocky Mountain lease transaction and requires us to maintain minimum liquidity of $50 million at all times during the term of the lease. We had sufficient liquidity to meet this covenant in 2022 and expect to have sufficient liquidity to meet this covenant in 2023. For a discussion of the Rocky Mountain lease transaction, see Note 4 of Notes to Consolidated Financial Statements.

Financing Activities

First Mortgage Indenture. At December 31, 2022, we had $11.9 billion of outstanding debt secured equally and ratably under our first mortgage indenture, an increase of $1.0 billion from December 31, 2021. From time to time, we may issue additional first mortgage obligations ranking equally and ratably with the existing first mortgage indenture obligations. The aggregate principal amount of obligations that may be issued under the first mortgage indenture is not limited; however, our ability to issue additional obligations under the first mortgage indenture is subject to certain requirements related to the certified value of certain of our tangible property, repayment of obligations outstanding under the first mortgage indenture and payments made under certain pledged contracts relating to property to be acquired. As of December 31, 2022, the amount of certified bondable additions and retired or defeased first mortgage indenture obligations available for the issuance of additional first mortgage indenture obligations was approximately $2.9 billion. In addition, as of December 31, 2022, we had over $290 million of property additions and certified progress payments under qualified engineering, procurement and construction contracts that, once certified in accordance with the first mortgage indenture, will be available for the issuance of additional first mortgage indenture obligations.

Department of Energy-Guaranteed Loans. We have loans from the Federal Financing Bank guaranteed by the Department of Energy to provide funding for over $4.6 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. At December 31, 2022, we had fully advanced the $4.6 billion available under the Department of Energy-guaranteed loans, of which $4.3 billion was outstanding. All of the debt advanced under the loan guarantee agreement is secured ratably with all other debt under our first mortgage indenture. For additional information regarding these loans, see Note 7a of Notes to Consolidated Financial Statements.

In addition, we have raised $2.8 billion of debt in the capital markets and expect to raise long-term financing for the remaining amounts not funded by the Department of Energy-guaranteed loans in the capital markets.

In accordance with the related promissory notes, we began principal repayments of our Department of Energy-guaranteed loans in February 2020. As of December 31, 2022, we had repaid $307.6 million under these loans and we expect to repay a total of approximately $486 million in principal on these loans by March 2024. We plan to issue first mortgage bonds to refinance the principal repaid before the in-service date of Vogtle Unit No. 4.

Rural Utilities Service-Guaranteed Loans. We currently have one approved Rural Utilities Service-guaranteed loan totaling $630.3 million to fund general and environmental improvements. We began borrowing from this loan in January 2021. As of December 31, 2022, we had $2.8 billion of debt outstanding under various Rural Utilities Service-guaranteed loans, an increase of $157.4 million from December 31, 2021. In 2022, we borrowed $317.2 million under various Rural Utilities Service-guaranteed loans for general and environmental improvements and for long-term funding of our Effingham acquisition.

All of the approved Rural Utilities Service-guaranteed loans are funded through the Federal Financing Bank, and the debt is secured ratably with all other debt under our first mortgage indenture.

Bond Financings. In April 2022, we issued $500 million of 4.50% first mortgage bonds, Series 2022A, to provide long-term financing for expenditures related to the construction of Vogtle Units No. 3 and No. 4. The bonds are due to mature April 2047 and are secured under our first mortgage indenture.

Capital Requirements

Cash Requirements. Our cash requirements relate primarily to operating expenses, capital expenditures and debt service. As discussed under "Sources of Capital and Liquidity," we fund our cash requirements through a mix of funds generated from operations and short- and long-term borrowings. For additional information regarding our contractual commitments, see Note 11 of Notes to Consolidated Financial Statements.

Capital Expenditures. As part of our ongoing capital planning, we forecast expenditures required for generating facilities and other capital projects. The table below details these forecasts for 2023 through 2025. Actual expenditures may vary from the estimates listed in the table because of factors such as changes in business conditions, design changes and rework required by regulatory bodies, delays in obtaining necessary regulatory approvals, construction delays, changing environmental requirements, and changes in cost of capital, equipment, material and labor.

Capital Expenditures(1)
(dollars in millions)

	2023	2024	2025	Total
Future Generation(2)	$ 625	$ 95	$ —	$ 720
Existing Generation(3)	224	327	279	830
Environmental Compliance(4)	12	10	33	55
Nuclear Fuel(5)	106	139	121	366
General Plant	10	5	3	18
Total	$ 977	$ 576	$ 436	$ 1,989

(1) Includes allowance for funds used during construction.

(2) Relates to construction of Vogtle Units No. 3 and No. 4, excluding initial nuclear fuel core. Forecasted expenditures are based on assumed in-service dates of June 2023 for Vogtle Unit No. 3 and March 2024 for Vogtle Unit No. 4. Includes $528 million in disputed payments to Georgia Power Company for the construction of Vogtle Unit No. 3 and No. 4.

(3) Normal additions and replacements to plant in-service.

(4) Pollution control equipment and facilities being installed at coal-fired Plant Scherer, including to comply with coal ash regulations.

(5) Includes nuclear fuel for existing nuclear units and initial nuclear fuel cores for Vogtle Units No. 3 and No. 4.

For information regarding the Vogtle project, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*" and "– *Financing Activities.*"

We are currently subject to extensive environmental regulations and may be subject to future additional environmental regulations, including future implementation of existing laws and regulations. Since alternative legislative and regulatory environmental compliance programs continue to be debated on a state and national level, we cannot predict what capital costs may ultimately be required. Therefore, environmental expenditures included in the above table only include amounts related to budgeted projects to comply with existing and certain well-defined rules and regulations and do not include amounts related to compliance with other, less certain rules.

Depending on how we and the other co-owners of Plant Scherer choose to comply with any future legislation or regulations, both capital expenditures and operating expenditures may be impacted. As required by the wholesale power contracts, we expect to be able to recover from our members all capital and operating expenditures made in complying with current and future environmental regulations.

For additional information regarding environmental regulation, see "BUSINESS – REGULATION – Environmental."

Credit Rating Risk

The table below sets forth our current ratings from S&P Global Ratings, Moody's Investors Service and Fitch Ratings.

Our Ratings	**S&P**	**Moody's**	**Fitch**
Long-term ratings:			
Senior secured rating	BBB+	Baa1	BBB
Issuer/unsecured rating(1)	BBB+	Baa2	BBB
Rating outlook	Negative	Stable	Stable
Short-term rating:			
Commercial paper rating	A-2	P-2	F2

(1) We currently have no long-term debt that is unsecured, however, pricing of our $1.2 billion syndicated line of credit is determined based on our unsecured or issuer ratings.

We have financial and other contractual agreements in place containing provisions which, upon a credit rating downgrade below specified levels, may require the posting of collateral in the form of letters of credit or other acceptable collateral. Our primary exposure to potential collateral postings is at rating levels of BBB-/Baa3 or below. As of December 31, 2022, our maximum potential collateral requirements were as follows:

At senior secured rating levels:

- approximately $50 million at a senior secured level of BBB-/Baa3,
- approximately $80 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured or issuer rating levels:

- approximately $20 million at a senior unsecured or issuer level of BBB-/Baa3,
- approximately $99 million at a senior unsecured or issuer rating level of BB+/Ba1 or below.

The Rural Utilities Service Loan Contract contains covenants that, upon a credit rating downgrade below investment grade by two rating agencies, could result in restrictions on issuing debt. Certain of credit agreements and pollution control bond agreements contain provisions based on our ratings that, upon a credit rating downgrade below specified levels, could result in increased interest rates. Also, borrowing rates, letter of credit fees and commitment fees in two of our lines of credit agreements are based on credit ratings and could increase if our ratings are lowered. None of these covenants and provisions, however, would result in acceleration of any debt due to credit rating downgrades.

Given our current level of ratings, our management does not have any reason to expect a downgrade that would result in any material impacts to our business. However, our ratings reflect only the views of the rating agencies and we cannot give any assurance that our ratings will be maintained at current levels for any period of time.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Due to our cost-based rate structure, we have limited exposure to market risks. However, changes in interest rates, equity prices, and commodity prices may result in fluctuations in member rates. We use derivatives only to manage this volatility and do not use derivatives for speculative purposes.

We have an executive risk management and compliance committee that provides general oversight over corporate compliance and all risk management activities, including, but not limited to, commodity trading, fuels management, insurance procurement, debt management, investment portfolio management, environmental compliance, and electric reliability compliance. This committee is comprised of our chief executive officer, chief operating officer, chief financial officer and the executive vice president, member relations. The risk management and compliance committee has implemented comprehensive risk management policies to manage and monitor credit, market price, and other corporate risks. These policies also specify controls and authorization levels related to various risk management activities. The committee frequently meets to review corporate exposures, risk management strategies, hedge positions, and compliance matters. The audit committee of our board of directors receives regular reports on corporate exposures, risk management and compliance activities and the actions of the risk management and compliance committee. For further discussion of our board of director's oversight of risk management and compliance, see "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE – Board of Directors' Role in Risk Oversight."

Interest Rate Risk

We are exposed to the risk of changes in interest rates relating to a portion of our debt. We categorize our debt as variable rate, which is debt that is subject to a change in interest rates within the next year, intermediate-term fixed rate debt, which is debt that is not subject to a change in interest rates within the next year, but is subject to a change in interest rates within the next five years, or long-term fixed rate debt, which is debt that is not subject to a change in interest rates within the next five years. At December 31, 2022, we had $847.1 million of variable rate debt, $312.5 million of intermediate-term fixed rate debt, and the remainder of our debt was long-term fixed rate debt. Our $847.1 million of variable rate debt at December 31, 2022, included $655.7 million of commercial paper outstanding (which typically has maturities of between 1 and 90 days) and $191.4 million of pollution control bonds (including $91.6 million of indexed variable rate bonds, which are subject to repricing weekly, and $99.8 million of term rate bonds tendered on February 1, 2023 and converted to indexed variable rate bonds subject to repricing weekly). Our $312.5 million of intermediate-term fixed rate debt at December 31, 2022 consisted of term rate debt subject to remarketing and repricing in February 2025.

At December 31, 2022, the weighted average interest rate on our variable rate debt was 4.6%. If, during 2023, interest rates on this debt changed a hypothetical 100 basis points on the respective repricing dates and remained at that level for the remainder of the year, annual interest expense would change by approximately $8.1 million.

Our objective in managing interest rate risk is to maintain a balance of long-term fixed, intermediate-term fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. At December 31, 2022, we had 6.7% of our total debt, including commercial paper, classified as variable rate and 2.5% of our total debt classified as intermediate-term fixed rate. The remaining 90.8% of our debt was classified as long-term fixed rate.

The operative documents underlying the pollution control bond debt contain provisions that allow us to convert the debt that is not fixed to maturity to a variety of variable interest rate modes (such as daily, weekly, monthly, commercial paper, or term rate mode), or to convert the debt to a fixed rate of interest to maturity. Having these interest rate conversion options improves our ability to manage our exposure to variable interest rates.

In addition to interest rate risk on existing debt, we are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4, as well as the short-term debt we are using for interim financing of this project.

Investment Risks

We maintain external trust funds (reflected as "Nuclear decommissioning trust fund" on the balance sheet) to fund our share of certain costs associated with the decommissioning of our nuclear plants as required by the Nuclear Regulatory Commission. We also maintain an internal reserve for decommissioning (included in "Long-term investments" on the balance sheet) from which funds can be transferred to the external trust fund, if necessary. For further discussion on our nuclear decommissioning trust funds, see Note 1 of Notes to Consolidated Financial Statements.

The allocation of equity and fixed income securities in both the external and internal funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs; however, the equity portion of these funds is exposed to price fluctuations in equity markets, and the values of fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the investment performance of the funds and periodically review asset allocation in accordance with our nuclear decommissioning fund investment policy. Our investment policy establishes targeted and permissible investment allocation ranges for equity and fixed income securities. The targeted asset allocation is diversified among various asset classes and investment styles. Specific investment guidelines are established with each of the investment advisors that are selected to manage a particular asset class or subclass.

The investment guidelines for equity securities typically limit the type of securities that may be purchased and the concentration of equity holdings in any one issuer and within any one sector. With respect to fixed-income securities, the investment guidelines set forth limits for the type of bonds that may be purchased, state that investments be primarily in securities with an assigned investment grade rating of BBB- or above and establish that the average credit quality of the portfolio typically be A+/A1 or higher.

Changes in interest rates also affect the market value of fixed income investments and rising interest rates during 2022 adversely affected the market value of fixed income investments in our nuclear and coal ash pond decommissioning funds. While we generally intend to hold these investments to maturity, sale of fixed income investments could lead to realizing losses on certain investments. While increases in interest rates may decrease the market value of fixed income assets, it may increase the amount of interest received for newly purchased fixed income investments and for funds invested in variable interest rate assets.

A 10% decline in the value of the internal and external funds' equity and fixed income securities as of December 31, 2022 would result in a loss of value to the funds of approximately $68.0 million.

We also maintain funds to finance our coal ash pond retirement obligations and for major maintenance expenses. We invest a portion of our coal ash decommissioning and major maintenance accounts in fixed income funds that are subject to changes in market value. A 10% decrease in the market value of these funds would be approximately $20.9 million.

Commodity Price Risk

We are also exposed to the risk of changing prices for fuels, including coal and natural gas.

Coal

We have interests in 982 megawatts of coal-fired nameplate capacity at Plant Scherer. We purchase coal under term contracts and in spot-market transactions. Some of our coal contracts provide volume flexibility and most have fixed or capped prices. Our existing contracts and stockpile are expected to provide fixed prices for 100% and 60% of our forecasted coal requirements for 2023 and 2024, respectively.

The objective of our coal procurement strategy is to ensure reliable coal supply and some price stability for our members. Our strategy permits coal commitments for up to 7 years. The procurement guidelines provide for layering in fixed and/or capped prices by annually entering into coal contracts for a portion of projected coal need for up to 7 years.

Natural Gas

We own or operate ten gas fired generation facilities totaling over 5,100 megawatts of nameplate capacity. See "PROPERTIES – Generating Facilities" and "BUSINESS – OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Smarr EMC*."

We maintain a natural gas hedge program, which assists our participating members in managing potential fluctuations in our power rates to them due to changes in the market price of natural gas. Currently, 19 of our members have elected to participate in our natural gas hedging program. This program layers in fixed prices for a portion of our forecasted natural gas requirements over a rolling time horizon of up to five and a half years. Natural gas swap arrangements are used for hedging under this program. Under our swap agreements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment. The fair value of the swaps at December 31, 2022 was a net asset of approximately $131.8 million, which represents the net amount we would have received if the swaps had been terminated as of that date. As of December 31, 2022, approximately 29% of our 2023 total system forecasted natural gas requirements were hedged under swap arrangements. A hypothetical 10% decline in the market price of natural gas would have resulted in a decrease of approximately $46.0 million to the fair value of our natural gas swap agreements. Additional members may elect to participate in our natural gas hedging program, and participating members may choose to discontinue their active participation in this program at any time.

Changes in Risk Exposure

Our exposure to changes in interest rates, the value of investments we hold, and commodity prices have not changed materially from the previous reporting period.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index To Financial Statements

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF REVENUES AND EXPENSES
For the years ended December 31, 2022, 2021 and 2020

	(dollars in thousands)		
	2022	2021	2020
Operating revenues:			
Sales to members	**$ 1,974,683**	$ 1,557,109	$ 1,377,010
Sales to non-members	**155,454**	47,754	608
Total operating revenues	**2,130,137**	1,604,863	1,377,618
Operating expenses:			
Fuel	**$ 1,045,089**	$ 598,996	$ 360,254
Production	**468,754**	410,708	427,808
Depreciation and amortization	**283,774**	275,346	248,888
Purchased power	**82,516**	69,346	68,484
Accretion	**55,953**	56,086	54,475
Total operating expenses	**$ 1,936,086**	$ 1,410,482	$ 1,159,909
Operating margin	**$ 194,051**	$ 194,381	$ 217,709
Other income:			
Investment income	**$ 57,564**	$ 45,932	$ 43,294
Amortization of deferred gains	**1,789**	1,789	1,789
Allowance for equity funds used during construction	**700**	385	374
Other	**12,191**	23,148	5,238
Total other income	**$ 72,244**	$ 71,254	$ 50,695
Interest charges:			
Interest expense	**$ 455,474**	$ 417,722	$ 409,145
Allowance for debt funds used during construction	**(262,573)**	(221,463)	(207,972)
Amortization of debt discount and expense	**11,690**	11,595	11,336
Net interest charges	**$ 204,591**	$ 207,854	$ 212,509
Net margin	**$ 61,704**	$ 57,781	$ 55,895

The accompanying notes are an integral part of these consolidated financial statements.

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2022 and 2021

	(dollars in thousands)	
	2022	2021
Assets		
Electric plant:		
In service	**$ 9,266,627**	$ 9,865,660
Right-of-use assets--finance leases	**302,732**	302,732
Less: Accumulated provision for depreciation	**(5,183,589)**	(5,565,724)
Electric plant in service, net	**4,385,770**	4,602,668
Nuclear fuel, at amortized cost	**388,303**	375,267
Construction work in progress	**7,716,035**	6,779,392
Total electric plant	**12,490,108**	11,757,327
Investments and funds:		
Nuclear decommissioning trust fund	**540,716**	659,910
Investment in associated companies	**78,937**	75,826
Long-term investments	**669,479**	711,379
Restricted investments	—	73,702
Other	**32,561**	31,991
Total investments and funds	**1,321,693**	1,552,808
Current assets:		
Cash and cash equivalents	**595,381**	579,350
Restricted cash and short-term investments	**104,431**	246,350
Short-term investments	**61,702**	—
Receivables	**220,015**	159,538
Inventories, at average cost	**297,951**	260,526
Prepayments and other current assets	**51,409**	62,286
Total current assets	**1,330,889**	1,308,050
Deferred charges and other assets:		
Regulatory assets	**1,212,305**	1,008,790
Prepayments to Georgia Power Company	**20,873**	27,124
Other	**113,502**	52,927
Total deferred charges	**1,346,680**	1,088,841
Total assets	**$ 16,489,370**	$ 15,707,026

The accompanying notes are an integral part of these consolidated financial statements.

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2022 and 2021

	(dollars in thousands)	
	2022	2021
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 1,192,127**	$ 1,130,423
Long-term debt	**11,512,513**	10,529,449
Obligations under finance leases	**52,937**	61,335
Obligation under Rocky Mountain transactions	**27,945**	26,151
Other	**2,256**	1,550
Total capitalization	**12,787,778**	11,748,908
Current liabilities:		
Long-term debt and finance leases due within one year	**322,102**	281,238
Short-term borrowings	**655,650**	1,095,971
Accounts payable	**203,705**	182,164
Accrued interest	**105,452**	96,410
Member power bill prepayments, current	**54,443**	26,102
Other current liabilities	**153,941**	36,123
Total current liabilities	**1,495,293**	1,718,008
Deferred credits and other liabilities:		
Asset retirement obligations	**1,343,743**	1,287,143
Member power bill prepayments, non-current	**53,877**	80,001
Regulatory liabilities	**792,190**	849,449
Other	**16,489**	23,517
Total deferred credits and other liabilities	**2,206,299**	2,240,110
Total equity and liabilities	**$ 16,489,370**	$ 15,707,026
Commitments and Contingencies (Notes 1, 7, 10, 11 and 12)		

The accompanying notes are an integral part of these consolidated financial statements.

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2022 and 2021

	(dollars in thousands) 2022	2021
Secured Long-term debt:		
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 1.03% to 8.21% (average rate of 3.40% at December 31, 2022) due in quarterly installments through 2048	**$ 2,758,753**	$ 2,601,365
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 1.44% to 4.01% (average rate of 2.94% at December 31, 2022) due in quarterly installments through 2044	**4,325,395**	3,925,493
First mortgage bonds payable:		
• Series 2006 First Mortgage Bonds, 5.534%, due 2031 through 2035	**300,000**	300,000
• Series 2007 First Mortgage Bonds, 6.191%, due 2024 through 2031	**500,000**	500,000
• Series 2009B First Mortgage Bonds, 5.95%, due 2039	**400,000**	400,000
• Series 2009 Clean renewable energy bond, 1.81%, due 2024	**2,021**	3,031
• Series 2010A First Mortgage Bonds, 5.375% due 2040	**450,000**	450,000
• Series 2011A First Mortgage Bonds, 5.25% due 2050	**300,000**	300,000
• Series 2012A First Mortgage Bonds, 4.20% due 2042	**250,000**	250,000
• Series 2014A First Mortgage Bonds, 4.55% due 2044	**250,000**	250,000
• Series 2016A First Mortgage Bonds, 4.25% due 2046	**250,000**	250,000
• Series 2018A First Mortgage Bonds, 5.05% due 2048	**500,000**	500,000
• Series 2020A First Mortgage Bonds, 3.75% due 2050	**450,000**	450,000
• Series 2022A First Mortgage Bonds, 4.50% due 2047	**500,000**	—
First mortgage notes issued in connection with the sale of pollution control revenue bonds through the Development Authorities of Appling, Burke, Heard and Monroe Counties, Georgia:		
• Series 2013A Appling, Burke and Monroe Term rate bonds, 1.50% through February 3, 2025, due 2038 through 2040	**212,760**	212,760
• Series 2017A, B Burke Indexed put bonds–weekly reset, 4.61% due 2040 through 2045	**91,645**	122,620
• Series 2017C, D Burke Fixed rate bonds, 4.125%, due 2041 through 2045	**200,000**	200,000
• Series 2017E Burke Term rate bonds, 3.25% through February 3, 2025, due 2041 through 2045	**100,000**	100,000
• Series 2017F Burke Term rate bonds, 3.00% through February 1, 2023, due 2041 through 2045	**99,785**	99,785
Total Secured Long-term debt	**$ 11,940,359**	$ 10,915,054
Obligations under finance leases	**61,335**	68,876
Obligation under Rocky Mountain transactions	**27,945**	26,151
Other	**2,256**	1,550
Patronage capital and membership fees	**1,192,127**	1,130,423
Subtotal	**$ 13,224,022**	$ 12,142,054
Less: long-term debt and finance leases due within one year	**(322,102)**	(281,238)
Less: unamortized debt issuance costs	**(96,588)**	(95,883)
Less: unamortized bond discounts on long-term debt	**(17,554)**	(16,025)
Total capitalization	**$ 12,787,778**	$ 11,748,908

The accompanying notes are an integral part of these consolidated financial statements.

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2022, 2021 and 2020

	(dollars in thousands)		
	2022	2021	2020
Cash flows from operating activities:			
Net margin	**$ 61,704**	$ 57,781	$ 55,895
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	**$ 451,899**	$ 400,681	$ 376,639
Accretion cost	**55,953**	56,086	54,475
Amortization of deferred gains	**(1,789)**	(1,789)	(1,789)
Allowance for equity funds used during construction	**(700)**	(385)	(374)
Deferred outage costs	**(30,926)**	(30,746)	(38,278)
Loss (gain) on sale of investments	**21,950**	(13,516)	(19,779)
Gain on sale of spare parts	**—**	(15,734)	—
Regulatory deferral of costs associated with nuclear decommissioning	**(54,529)**	(19,318)	(10,691)
Other	**(712)**	(2,528)	(5,587)
Change in operating assets and liabilities:			
Receivables	**(68,550)**	(5,693)	(3,659)
Inventories	**(36,235)**	23,232	(2,409)
Prepayments and other current assets	**25,031**	577	(23,754)
Accounts payable	**7,008**	31,790	1,504
Accrued interest	**9,042**	23,976	6,539
Accrued taxes	**52,764**	(36,301)	33,588
Other current liabilities	**32,300**	(14,292)	9,439
Member power bill prepayments	**2,217**	(38,078)	(67,281)
Rate management program collections, net	**19,847**	144,763	146,917
Total adjustments	**$ 484,570**	$ 502,725	$ 455,500
Net cash provided by operating activities	**$ 546,274**	$ 560,506	$ 511,395
Cash flows from investing activities:			
Property additions	**$ (1,156,383)**	$ (1,203,050)	$ (1,335,380)
Plant acquisition	**(86,826)**	(233,156)	—
Activity in nuclear decommissioning trust fund – Purchases	**(204,500)**	(675,153)	(578,610)
– Proceeds	**194,046**	667,344	570,294
Proceeds from the sale of spare parts	**—**	18,500	—
Decrease in restricted investments	**246,022**	167,535	46,003
Activity in other long-term investments – Purchases	**(185,092)**	(433,532)	(425,628)
– Proceeds	**107,082**	246,256	186,219
Other	**4,040**	14,843	7,982
Net cash used in investing activities	**$ (1,081,611)**	$ (1,430,413)	$ (1,529,120)
Cash flows from financing activities:			
Long-term debt proceeds	**$ 1,414,925**	$ 757,032	$ 2,221,685
Long-term debt payments	**(397,162)**	(468,577)	(1,334,368)
(Decrease) increase in short-term borrowings, net	**(440,321)**	712,473	101,128
Other	**2,526**	44,618	(13,821)
Net cash provided by financing activities	**579,968**	1,045,546	974,624
Net increase (decrease) in cash, cash equivalents and restricted cash	**$ 44,631**	$ 175,639	$ (43,101)
Cash, cash equivalents and restricted cash at beginning of period	**581,150**	405,511	448,612
Cash, cash equivalents and restricted cash at end of period	**$ 625,781**	$ 581,150	$ 405,511
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	**$ 182,066**	$ 170,605	$ 193,063
Supplemental disclosure of non-cash investing and financing activities:			
Change in asset retirement obligations	**$ 10,486**	$ 107,677	$ 18,709
Accrued property additions at end of period	**$ 79,204**	$ 65,686	$ 89,640

The accompanying notes are an integral part of these consolidated financial statements.

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF PATRONAGE CAPITAL AND MEMBERSHIP FEES
For the years ended December 31, 2022, 2021 and 2020

	(dollars in thousands)
Balance at December 31, 2019	$ 1,016,747
Components of comprehensive margin in 2020:	
Net margin	55,895
Balance at December 31, 2020	$ 1,072,642
Components of comprehensive margin in 2021:	
Net margin	57,781
Balance at December 31, 2021	$ 1,130,423
Components of comprehensive margin in 2022:	
Net margin	**61,704**
Balance at December 31, 2022	**$ 1,192,127**

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the years ended December 31, 2022, 2021 and 2020

1. Summary of significant accounting policies:

a. Business description

Oglethorpe Power Corporation is an electric membership corporation incorporated in 1974 and headquartered in metropolitan Atlanta, Georgia that operates on a not-for-profit basis. We are owned by 38 retail electric distribution cooperative members in Georgia. We provide wholesale electric power from a combination of owned and co-owned generating units of which our ownership share totals 7,744 megawatts of summer planning reserve capacity. We also manage and operate Smarr EMC which owns 733 megawatts of summer planning reserve capacity. In addition, we supply financial and management services to Green Power EMC, which purchases energy from renewable energy facilities totaling 584 megawatts of capacity, including 552 megawatts sourced by solar energy. Georgia Power Company is a co-owner and the operating agent of our nuclear and coal-fired generating units. Our members in turn distribute energy on a retail basis to approximately 4.4 million people.

b. Basis of accounting

Our consolidated financial statements include our accounts and the accounts of our majority-owned and controlled subsidiary. We have determined that there are no accounts of variable interest entities for which we are the primary beneficiary. We have eliminated any intercompany profits and transactions in consolidation. Certain prior year amounts have been reclassified to conform with current year presentation.

We follow generally accepted accounting principles in the United States. We maintain our accounts in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission as modified and adopted by the Rural Utilities Service. We also apply the accounting guidance for regulated operations.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of December 31, 2022 and 2021 and the reported amounts of revenues and expenses for each of the three years in the period ended December 31, 2022. Examples of estimates used include items related to our asset retirement obligations. Accounting for asset retirement and environmental obligations requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Estimating the amount and timing of future expenditures includes, among other things, making projections of when assets will be retired and ultimately decommissioned, the amount of decommissioning costs, and how costs will escalate with inflation. Actual results could differ from those estimates.

c. Patronage capital and membership fees

We are organized and operate as a cooperative. Our members paid a total of $190 in membership fees. Patronage capital includes retained net margin. Any excess of revenues over expenditures from operations is treated as an advance of capital by our members and is allocated to each member on the basis of their fixed percentage capacity cost responsibilities in our generation resources.

Any distributions of patronage capital are subject to the discretion of our board of directors, subject to first mortgage indenture requirements. Under our first mortgage indenture, we are prohibited from making any distribution of patronage capital to our members if, at the time of or after giving effect to, (i) an event of default exists under the indenture, (ii) our equity as of the end of the immediately preceding fiscal quarter is less than 20% of our total long-term debt and equities, or (iii) the aggregate amount expended for distributions on or after the date on which our equity first reaches 20% of our total long-term debt and equities exceeds 35% of our aggregate net margins earned after such date. This last restriction, however will not apply if, after giving effect to such distribution, our equity as of the end of the immediately preceding fiscal quarter is not less than 30% of our long-term debt and equities.

d. Margin policy

We are required under our first mortgage indenture to produce a margins for interest ratio of at least 1.10 for each fiscal year. For the years 2022, 2021 and 2020, we achieved a margins for interest ratio of 1.14.

e. Revenue recognition

As an electric membership cooperative, our principal business is providing wholesale electric service to our members. Our operating revenues are derived primarily from wholesale power contracts we have with each of our 38 members. These contracts, which extend to December 31, 2050, are substantially identical and obligate our members jointly and severally to pay all expenses associated with owning and operating our power supply business. As a cooperative, we operate on a not-for-profit basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to establish reasonable reserves and meet certain financial coverage requirements. We also sell energy and capacity to non-members through industry standard contracts and negotiated agreements, respectively. We do not have multiple operating segments.

Pursuant to our contracts, we primarily provide two services, capacity and energy. Capacity and energy revenues are recognized by us upon transfer of control of promised services to our members and non-members in an amount that reflects the consideration we expect to receive in exchange for those services. Capacity and energy are distinct and we account for them as separate performance obligations. The obligations to provide capacity and energy are satisfied over time as the customer simultaneously receives and consumes the benefit of these services. Both performance obligations are provided directly by us and not through a third party.

Each of our members is obligated to pay us for capacity and energy we furnish under its wholesale power contract in accordance with rates we establish. We review our rates periodically but are required to do so at least once every year. Revenues from our members are derived through a cost-plus rate structure which is set forth as a formula in the rate schedule to the wholesale power contracts. The formulary rate provides for the pass-through of our (i) fixed costs (net of any income from other sources) plus a targeted margin as capacity revenues and (ii) variable costs as energy revenues from our members. Power purchase and sale agreements between us and non-members obligate each non-member to pay us for capacity, if any, and energy furnished in accordance with the prices mutually agreed upon. Margins produced from non-member sales are included in our rate schedule formula and reduce revenue requirements from our members. As of December 31, 2022, we did not have any significant long-term contracts with non-members.

The consideration we receive for providing capacity services to our members is determined by our formulary rate on an annual basis. The components of the formulary rate associated with capacity costs include the annual budget of fixed costs, a targeted margin and income from other sources. Capacity revenues, therefore, vary to the extent these components vary. Fixed costs include items such as fixed operation and maintenance expenses, administrative and general expenses, depreciation and interest. Year to year, capacity revenue fluctuations are generally due to the recovery of fixed operation and maintenance expenses. Fixed costs also include certain costs, such as major maintenance costs, which will be recognized as expense in future periods. Recognition of revenues associated with these future expenses is deferred pursuant to Accounting Standards Codification (ASC) 980, Regulated Operations. The regulatory liabilities are amortized to revenue in accordance with the associated revenue deferral plan as the expenses are recognized. For information regarding regulatory accounting, see Note 1q.

Capacity revenues are recognized by us for standing ready to deliver electricity to our customers. Our member capacity revenues are based on the associated costs we expect to recover in a given year and are recognized and billed to our members in equal monthly installments over the course of the year regardless of whether our generation and purchased power resources are dispatched to produce electricity. Non-member capacity revenues are billed and recognized in accordance with the terms of the associated contract.

We have a power bill prepayment program pursuant to which our members may prepay future capacity costs and receive a discount. As this program provides us with financing, we adjust our capacity revenues by the amount of the discount, which is based on our avoided cost of borrowing. For additional information regarding our member prepayment program, see Note 1p.

We satisfy our performance obligations to deliver energy as energy is delivered to the applicable meter points. We determine the standard selling price for energy we deliver to our members based upon the variable costs incurred to generate or purchase that energy. Fuel expense is the primary variable cost. Energy revenue recognized equals the actual variable expenses incurred in any given accounting period. Our member energy revenues fluctuate from period to period based on several factors, including fuel costs, weather and other seasonal factors, load requirements in our members' service territories, variable operating costs, the availability of electric generation resources, our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights, and by members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers. In 2022, 2021 and 2020, we provided approximately 58%, 62% and 57% of our members' energy requirements, respectively. The standard selling price for our energy revenues from non-members is the price mutually agreed upon.

We are required under our first mortgage indenture to produce a margins for interest ratio of at least 1.10 for each fiscal year. For 2022, 2021 and 2020, our board approved, and we achieved, a targeted margins for interest ratio of 1.14. Historically, our board of directors has approved adjustments to revenue requirements by year end such that revenue in excess of that required to meet the targeted margins for interest ratio is refunded to the members. Given that our capacity revenues are based upon budgeted expenditures and generally recognized and billed to our members in equal monthly installments over the course of the year, we may recognize capacity revenues that exceed our actual fixed costs and targeted margins in any given interim reporting period. At each interim reporting period we assess our projected revenue requirements through year end to determine whether a refund to our members of excess consideration is likely. If so, we reduce our capacity revenues and recognize a refund liability to our members. Refund liabilities, if any, are included in accounts payable on our consolidated balance sheets. As of December 31, 2022 and December 31, 2021, we recognized refund liabilities totaling $28,471,000 and $30,029,000, respectively. Based on our current agreements with non-members, we do not refund any consideration received from non-members.

Sales to members were as follows:

	(dollars in thousands)		
	2022	2021	2020
Capacity revenues	**$ 984,036**	$ 946,662	$ 971,071
Energy revenues	**990,647**	610,447	405,939
Total	**$ 1,974,683**	$ 1,557,109	$ 1,377,010

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2022, 2021 or 2020:

	2022	2021	2020
Jackson EMC	**16.0 %**	15.2 %	15.2 %
GreyStone Power Corporation, an EMC	**10.0 %**	8.7 %	8.7 %
Cobb EMC	**9.5 %**	12.3 %	13.2 %

Receivables from contracts with our members at December 31, 2022 and December 31, 2021 were $187,401,000 and $143,715,000, respectively.

Energy revenues from non-members were primarily due from the sale of the Effingham deferring members' output into the wholesale market. In 2022, we recognized capacity revenues from non-members relating to our Washington County acquisition. For additional information regarding the Washington County acquisition, see Note 14.

Sales to non-members were as follows:

	(dollars in thousands)		
	2022	2021	2020
Energy revenues	**$ 155,372**	$ 47,754	$ 608
Capacity revenues	**82**	—	—
Total	**$ 155,454**	$ 47,754	$ 608

Electric capacity and energy revenues are recognized by us without any obligation for returns, warranties or taxes collected. As our members are jointly and severally obligated to pay all expenses associated with owning and operating our power supply business and we perform an on-going assessment of the credit worthiness of non-members and have not had a history of any write-offs from non-members, we have not recorded an allowance for doubtful accounts associated with our receivables from members or non-members.

We have a rate management program that allows us to expense and recover interest costs associated with the construction of Vogtle Units No. 3 and No. 4, on a current basis, that would otherwise be deferred or capitalized. The subscribing members of Vogtle Units No. 3 and No. 4 can elect to participate in this program on an annual basis. Under this program, amounts billed to participating members in 2022, 2021 and 2020 were $14,796,000, $15,693,000 and $14,684,000, respectively. The cumulative amount billed since inception of the program totaled $126,432,000.

In 2018, we began an additional rate management program that allows us to recover future expense on a current basis from our members. In general, the program allows for additional collections over a five-year period with those amounts then applied to billings over the subsequent five-year period. The program is designed primarily as a mechanism to assist our members in managing the rate impacts associated with the commercial operation of the new Vogtle units. During the first quarter of 2022, we began applying billing credits to some of our participating members within this program. Under this program, amounts billed to participating members, net of credits, during 2022, 2021 and 2020 were $11,774,000, $143,000,000 and $125,842,000 respectively. Funds collected through this program are invested and held until applied to members’ bills. Investments that mature and are expected to be applied to members' bills within the next twelve months are included in the Short-term investments line item within our consolidated balance sheets. In conjunction with this program, we are applying regulated operations accounting to defer these revenues and related investment income on the funds collected. Amounts deferred under the program will be amortized to income when applied to members’ bills. The net cumulative amount billed since inception of the program totaled $369,102,000.

f. Receivables

A substantial portion of our receivables are related to capacity and energy sales to our members. These receivables are recorded at the invoiced amount and do not bear interest. Our members are required through the wholesale power contracts to reimburse us for all costs, plus a margin requirement. Receivables from contracts with our members at December 31, 2022, 2021 and 2020 were $187,401,000, $143,715,000 and $135,462,000, respectively. Payment is typically received the following month in which capacity and energy are billed. Estimated energy charges are billed based on the amount of energy supplied during the month and are adjusted when actual costs are available, generally the following month.

The remainder of our receivables is primarily related to transactions with non-members from the sale of the Effingham deferring members' output, affiliated companies and investment income. Our receivables from non-members were $32,614,000 at December 31, 2022. Our receivables from non-members were insignificant at December 31, 2021.

As a result of our historical experience, the short duration lifetime of our receivables and the short time horizon over which to consider expectations of future economic conditions, we have assessed that non-collection of the cost basis of our receivables is remote. During 2022, 2021 and 2020, no credit losses were recognized on any receivables that arose from contracts with members or non-members.

g. Nuclear fuel cost

The cost of nuclear fuel is amortized to fuel expense based on usage. The total nuclear fuel expense for 2022, 2021 and 2020 amounted to $73,871,000, $77,366,000, and $75,968,000, respectively.

Contracts with the U.S. Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at Plants Hatch and Vogtle. The Department of Energy failed to begin disposing of spent fuel in January 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants has pursued and continues to pursue legal remedies against the Department of Energy for breach of contract.

Georgia Power filed claims against the U.S. government in 2014 (as amended) seeking damages for spent nuclear fuel storage costs at Plant Hatch and Plant Vogtle Units No. 1 and No. 2 covering the period from January 1, 2011 through December 31, 2014. On June 12, 2019, the U.S. Court of Federal Claims granted Georgia Power’s motion for summary judgement on damages not disputed by the U.S. Government and awarded the undisputed damages to Georgia Power. However, these undisputed damages are not collectable by Georgia Power and no amounts will be recognized in our financial statements until the court enters final judgement on the remaining damages.

Georgia Power filed additional claims against the U.S. government in 2017 seeking damages for spent nuclear fuel storage costs at Plant Hatch and Plant Vogtle Units No. 1 and No. 2 covering the period from January 1, 2015 through December 31, 2017. On August 13, 2020, Georgia Power filed amended complaints in each of the lawsuits against the U.S. government in the Court of Federal Claims for damages from January 1, 2018 to December 31, 2019.

Our share of the claims outstanding for the period January 1, 2011 through December 31, 2019 are approximately $84,000,000. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the consolidated financial statements as of December 31, 2022 or December 31, 2021 for these claims. The final outcome of these matters cannot be determined at this time.

Both Plants Hatch and Vogtle have on-site dry spent storage facilities in operation. Facilities at both plants can be expanded to accommodate spent fuel through the expected life of each plant.

h. Asset retirement obligations and other retirement costs

Asset retirement obligations are legal obligations associated with the retirement of long-lived assets. These obligations represent the present value of the estimated costs for an asset's future retirement discounted using a credit-adjusted risk-free rate, and are recorded in the period in which the liability is incurred. The liabilities we have recognized primarily relate to the decommissioning of our nuclear facilities and coal ash ponds. In addition, we have retirement obligations related to gypsum cells, powder activated carbon cells, landfill sites and asbestos removal. Under the accounting provision for regulated operations, we record a regulatory asset or liability to reflect the difference in timing of recognition of the costs related to nuclear and coal ash related decommissioning for financial statement purposes and for ratemaking purposes.

Periodically, we obtain revised cost studies associated with our nuclear and fossil plants' asset retirement obligations. Actual retirement costs may vary from these estimates. The estimated costs of nuclear and coal ash pond decommissioning are based on the most recent studies performed in 2021 and 2022, respectively.

The following table reflects the details of the asset retirement obligations included in the consolidated balance sheets for the years 2022 and 2021.

	(dollars in thousands)			
	Nuclear	**Coal Ash Pond**	**Other**	**Total**
Balance at December 31, 2021	$ 778,214	$ 442,686	$ 66,243	1,287,143
Liabilities settled	**—**	**(10,134)**	**(184)**	**(10,318)**
Accretion	**41,892**	**12,196**	**1,865**	**55,953**
Deferred accretion	**—**	**479**	**—**	**479**
Change in cash flow estimates	**—**	**16,301**	**(5,815)**	**10,486**
Balance at December 31, 2022	**$ 820,106**	**$ 461,528**	**$ 62,109**	**$ 1,343,743**

	(dollars in thousands)			
	Nuclear	Coal Ash Pond	Other	Total
Balance at December 31, 2020	$ 738,217	$ 346,589	$ 51,177	$ 1,135,983
Liabilities settled	—	(17,046)	4,642	(12,404)
Accretion	43,206	11,157	1,723	56,086
Deferred accretion	—	(199)	—	(199)
Change in cash flow estimates	(3,209)	102,185	8,701	107,677
Balance at December 31, 2021	$ 778,214	$ 442,686	$ 66,243	$ 1,287,143

Asset Retirement Obligations

Nuclear Decommissioning. Nuclear decommissioning cost estimates are based on site studies and assume prompt dismantlement and removal of both the radiated and non-radiated portions of the plant from service, as well as the management of spent fuel. We do not have a legal obligation to decommission non-radiated structures and, therefore, these costs are excluded from the related asset retirement obligation and the amounts in the table above. Actual decommissioning costs may vary from these estimates because of, but not limited to, changes in the assumed date of decommissioning, changes in regulatory requirements, changes in technology, and changes in costs of labor, materials and equipment. Our most recent assessment of the nuclear asset obligation, which occurred in 2021 resulted in a slight decrease in the obligation for nuclear decommissioning. Our portion of the estimated costs of decommissioning co-owned nuclear facilities are as follows:

	(dollars in thousands)			
2021 site study	Hatch Unit No. 1	Hatch Unit No. 2	Vogtle Unit No. 1	Vogtle Unit No. 2
Expected start date of decommissioning	2034	2038	2047	2049
Estimated costs based on site study in 2021 dollars:				
Radiated structures	$ 227,000	$ 236,000	$ 200,000	$ 213,000
Spent fuel management	60,000	51,000	58,000	53,000
Non-radiated structures	15,000	21,000	24,000	31,000
Total estimated site study costs	$ 302,000	$ 308,000	$ 282,000	$ 297,000

We have established funds to comply with the Nuclear Regulatory Commission regulations regarding the decommissioning of our nuclear plants. See Note 1i for information regarding the nuclear decommissioning funds.

We apply the provision of regulated operations to nuclear decommissioning transactions such that collections and investment income (interest, dividends and realized gains and losses) of our nuclear decommissioning funds are compared to the associated decommissioning expenses with the difference deferred as regulatory asset or liability. As this difference is largely attributable to the timing of decommissioning fund earnings, the difference is recorded as an adjustment to investment income in our consolidated statements of revenues and expenses. Unrealized gains and losses of the decommissioning funds are recorded directly to the regulatory asset or liability for asset retirement obligations in accordance with our ratemaking treatment.

Coal Combustion Residuals. Coal combustion residuals (CCR) are subject to Federal and State regulations. Our obligations associated with CCR are primarily for the closure of coal ash ponds. During 2022 and 2021, assessments of the coal ash pond asset retirement obligation resulted in a $16,301,000 increase and a $102,185,000 increase in cash flow estimates for coal ash decommissioning, respectively. Estimates are based on various assumptions including, but not limited to, closure and post-closure cost estimates, timing of expenditures, escalation factors, discount rates and methods for complying with the CCR regulations. The 2022 increase in cash flow estimates was primarily due to the Georgia Public Service Commission's approval of Georgia Power's request to revise the closure of the Plant Wansley coal ash pond from in-place to removal. Additional adjustments to the asset retirement obligations are expected periodically due to potential changes in estimates and assumptions.

We have internally segregated the funds collected for coal ash pond and other CCR decommissioning costs, including earnings thereon. As of December 31, 2022 and December 31, 2021, the fund balances were $153,208,000 and $140,474,000, respectively.

We apply the provision of regulated operations to coal ash pond and other CCR decommissioning transactions such that collections and investment income (interest, dividends and realized gains and losses) are compared to the associated decommissioning expenses with the difference deferred to or amortized from the regulatory asset. This difference is recorded to the associated expenses in our consolidated statements of revenues and expenses. Unrealized gains and losses of the associated decommissioning fund are recorded directly to the regulatory asset in accordance with our ratemaking treatment.

Other Retirement Costs

Accounting standards for asset retirement and environmental obligations do not apply to a retirement cost for which there is no legal obligation to retire the asset, and non-regulated entities are not allowed to accrue for such future retirement costs. We continue to recognize retirement costs for these other obligations in our depreciation rates under the accounting provisions for regulated operations. Accordingly, the accumulated retirement costs for other obligations are reflected as a regulatory liability in our balance sheets. For information regarding accumulated retirement costs for other obligations, see Note 1q.

i. Nuclear decommissioning funds

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. The NRC definition of decommissioning does not include all costs that may be associated with decommissioning, such as spent fuel management and non-radiated structures.

We have established external trust funds to comply with the NRC's regulations. Upon approval by the NRC, any funding in the external trust in excess of their requirements may be used for other decommissioning costs. In 2022, additional amounts totaling $2,643,000 were contributed to the external trust funds. In 2021, no additional amounts were contributed to the external trust funds. These funds are managed by unrelated third party investment managers with the discretion to buy, sell and invest pursuant to investment objectives and restrictions set forth in agreements entered into between us and the investment managers. We record the investment securities held in the nuclear decommissioning trust fund at fair value, as disclosed in Note 2. Because day-to-day investment decisions are made by third party investment managers, the ability to hold investments in unrealized loss positions is outside our control.

In addition to the external trust funds, we maintain unrestricted investments internally designated for nuclear decommissioning. These internal funds are available to be utilized to fund the external trust funds, should additional funding be required, as well as other decommissioning costs outside the scope of the NRC funding regulations. The funds are included in long-term investments on our consolidated balance sheets. In 2022 we contributed $8,350,000 into the internal funds and in 2021 we contributed $9,750,000 into the internal funds.

The following table outlines the fair value of our nuclear decommissioning funds as of December 31, 2022 and December 31, 2021. The funds were invested in a diversified mix of approximately 69% equity and 31% fixed income securities in 2022 and 71% equity and 29% fixed income securities in 2021.

	2022				
External Trust Funds:	(dollars in thousands)				
	Cost 12/31/2021	**Purchases**	**Net Proceeds[(1)]**	**Unrealized Gain(Loss)**	**Fair Value 12/31/2022**
Equity	$ 223,336	$ **9,255**	$ **(3,655)**	$ **131,572**	$ **360,508**
Debt	204,935	**191,958**	**(203,907)**	**(12,869)**	**180,117**
Other	(795)	**3,287**	**(2,401)**	**—**	**91**
	$ 427,476	$ **204,500**	$ **(209,963)**	$ **118,703**	$ **540,716**

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends and fees of $5,463,000.

	2022				
Internal Funds:	(dollars in thousands)				
	Cost 12/31/2021	**Purchases**	**Net Proceeds[(1)]**	**Unrealized Gain(Loss)**	**Fair Value 12/31/2022**
Equity	$ 68,914	$ **—**	$ **10,005**	$ **18,995**	$ **97,914**
Debt	46,856	**76,207**	**(79,828)**	**(2,741)**	**40,494**
	$ 115,770	$ **76,207**	$ **(69,823)**	$ **16,254**	$ **138,408**

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of $6,384,000.

	2021				
External Trust Funds:	(dollars in thousands)				
	Cost 12/31/2020	Purchases	Net Proceeds[(1)]	Unrealized Gain(Loss)	Fair Value 12/31/2021
Equity	$ 212,387	$ 50,309	$ (39,360)	$ 230,710	$ 454,046
Debt	196,810	583,003	(574,878)	1,724	206,659
Other	17	41,841	(42,653)	—	(795)
	$ 409,214	$ 675,153	$ (656,891)	$ 232,434	$ 659,910

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends and fees of $18,261,000.

Internal Funds:	2021 (dollars in thousands)				
	Cost 12/31/2020	Purchases	Net Proceeds(1)	Unrealized Gain(Loss)	Fair Value 12/31/2021
Equity	$ 50,647	$ —	$ 18,267	$ 44,735	$ 113,649
Debt	50,467	204,150	(207,761)	181	47,037
	$ 101,114	$ 204,150	$ (189,494)	$ 44,916	$ 160,686

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of $14,656,000.

Realized and unrealized gains and losses of the nuclear decommissioning funds that would be recorded in earnings by a non-regulated entity are directly deducted from or added to the regulatory asset or liability for asset retirement obligations in accordance with our rate-making treatment.

The nuclear decommissioning trust fund has produced an average annualized return of approximately 5.9% in the last ten years and 5.8% since inception in 1990. Based on current funding and cost study estimates, we expect the current balances and anticipated investment earnings of our decommissioning fund assets to be sufficient to meet all of our future nuclear decommissioning costs. Notwithstanding the above assumption, our management believes that increases in cost estimates of decommissioning can be recovered in future rates.

j. Depreciation

Depreciation is computed on additions when they are placed in service using the composite straight-line method. We use prescribed depreciation rates as well as site specific rates determined through depreciation studies as approved by the Rural Utilities Service. The depreciation rates for steam, nuclear and other production in the table below reflect revised rates from depreciation rate studies completed in 2020 or 2021. Site specific depreciation studies are performed every five years. Annual weighted average depreciation rates in effect in 2022, 2021, and 2020 were as follows:

	Remaining Useful Life Range in years*	**2022**	2021	2020
Steam production	20-22	**13.77 %**	14.47 %	2.58 %
Nuclear production	12-27	**2.17 %**	2.18 %	1.93 %
Hydro production	44	**2.00 %**	2.00 %	2.00 %
Other production	17-26	**2.68 %**	2.60 %	2.61 %
Transmission	12-27	**2.75 %**	2.75 %	2.75 %
General	1-43	**2.00-33.33%**	2.00-33.33%	2.00-33.33%

* Based on estimated retirement dates as of 2022. Actual retirement dates may be different. Remaining useful lives for nuclear production are based on the expiration date of the applicable operating license approved by the NRC.

Depreciation expense for the years 2022, 2021 and 2020 was $278,452,000, $269,280,000, and $242,822,000, respectively. In 2021, the composite depreciation rate for Plant Wansley was increased in anticipation of the plant's retirement in 2022. In addition to the depreciation expense recognized in 2022 and 2021, $165,013,000 and $204,891,000, respectively, of Plant Wansley's depreciation expense was deferred. Subsequent to the retirement of Plant Wansley, we amortized $8,120,000 of deferred depreciation expense in 2022. See Note 1q for information regarding regulatory assets and liabilities.

k. Electric plant

Electric plant is stated at original cost, which is the cost of the plant when first dedicated to public service, including acquisition adjustments, if any, plus the cost of any subsequent additions. Cost includes an allowance for the cost of equity and debt funds used during construction and allocable overheads. For the years 2022, 2021 and 2020, the allowance for funds used during construction rates were 4.03%, 3.90% and 4.00%, respectively.

Replacements and renewals of items considered to be units of property, the lowest level of property for which we capitalize, are charged to the plant accounts. At the time properties are disposed of, the original cost is charged to the accumulated provision for depreciation. Cost of removal, less salvage, is charged to a regulatory liability, accumulated retirement costs for other assets. Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are charged to expense, including certain major maintenance costs at our natural gas-fired plants.

l. Cash and cash equivalents

We consider all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents. Temporary cash investments with maturities at the time of purchase of more than three months are classified as short-term investments.

m. Restricted cash and investments

Restricted investments consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account that are held by the U.S. Treasury, acting through the Federal Financing Bank. We can only utilize these investments for future Rural Utilities Service-guaranteed Federal Financing Bank debt service payments. For the period from January 1, 2021 to September 30, 2021, deposits earned interest at 4% per annum. Beginning October 1, 2021, the rate was set at the 1-year floating treasury rate, which was 0.09% per annum, and will be reset annually on October 1 of each year thereafter. On October 1, 2022, the rate was reset at the 1-year floating treasury rate, which was 4.05% per annum. The program no longer allows additional funds to be deposited into the account. At December 31, 2022 and 2021, we had restricted investments totaling $74,031,000 and $320,052,000, respectively, of which $74,031,000 and $246,350,000, respectively, were classified as current.

Restricted cash consists of collateral posted by our counterparties under our natural gas swap agreements. The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the consolidated balance sheets that sum to the total of the same such amounts reported in the consolidated statements of cash flows.

Classification		
	Twelve months ended	
	December 31, 2022	December 31, 2021
	(dollars in thousands)	
Cash and cash equivalents	**$ 595,381**	$ 579,350
Restricted cash included in restricted cash and short-term investments	**30,400**	1,800
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	**$ 625,781**	$ 581,150

n. Inventories

We maintain inventories of fossil fuel and spare parts, including materials and supplies for our generation plants. These inventories are stated at weighted average cost.

The fossil fuel inventories primarily include the direct cost of coal and related transportation charges. The cost of fossil fuel inventories is carried at weighted average cost and is charged to fuel expense as consumed. The spare parts inventories primarily include the direct cost of generating plant spare parts. The spare parts inventory is carried at weighted average cost and the parts are charged to expense or capitalized, as appropriate when installed.

At December 31, 2022 and December 31, 2021, fossil fuels inventories were $64,386,000 and $44,601,000, respectively. Inventories for spare parts at 2022 and 2021 were $233,565,000 and $215,925,000, respectively.

o. Deferred charges and other assets

Other deferred charges primarily represent advance deposits to Georgia Power Company related to the Vogtle construction project and future generation project costs.

For a discussion regarding regulatory assets, see Note 1q.

p. Deferred credits and other liabilities

We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills monthly and are recorded as a reduction to member revenues. The prepayments are being credited against members' power bills through December 2028, with the majority of the balance scheduled to be credited by the end of 2023.

Deferred credits and other liabilities also consists of asset retirement obligations as discussed in Note 1h and regulatory liabilities in Note 1q.

q. Regulatory assets and liabilities

We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery from our members in future revenues through rates established under the wholesale power contracts we have with each of our members. These contracts extend through December 31, 2050. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from members.

	(dollars in thousands)			
		2022		2021
Regulatory Assets:				
Premium and loss on reacquired debt(a)	**$**	**29,494**	$	33,200
Amortization on financing leases(b)		**31,908**		34,179
Outage costs(c)		**29,317**		31,956
Asset retirement obligations – Ashpond and other(l)		**353,212**		335,231
Asset retirement obligations – Nuclear(l)		**32,192**		—
Depreciation expense - Plant Vogtle(d)		**35,549**		36,973
Depreciation expense - Plant Wansley(e)		**361,784**		204,891
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs(f)		**54,701**		55,857
Interest rate options cost(g)		**136,827**		131,556
Deferral of effects on net margin – Smith Energy Facility(h)		**136,730**		142,675
Other regulatory assets(o)		**10,591**		2,272
Total Regulatory Assets	**$**	**1,212,305**	$	1,008,790
Regulatory Liabilities:				
Accumulated retirement costs for other obligations(i)	**$**	**35,580**	$	22,197
Deferral of effects on net margin – Hawk Road Energy Facility(h)		**16,636**		17,253
Deferral of effects on net margin – Effingham Energy Facility(p)		**14,825**		—
Major maintenance reserve(j)		**74,584**		73,059
Amortization on financing leases(b)		**5,557**		8,457
Deferred debt service adder(k)		**154,514**		138,897
Asset retirement obligations – Nuclear(l)		**—**		164,256
Revenue deferral plan(m)		**357,460**		359,799
Natural gas hedges(n)		**131,804**		63,994
Other regulatory liabilities(o)		**1,230**		1,537
Total Regulatory Liabilities	**$**	**792,190**	$	849,449
Net regulatory assets	**$**	**420,115**	$	159,341

(a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt that are being amortized over the lives of the refunding debt, which range up to 21 years.

(b) Represents the difference between expense recognized for rate-making purposes versus financial statement purposes related to finance lease payments and the aggregate of the amortization of the asset and interest on the obligation.

(c) Consists of both coal-fired maintenance and nuclear refueling outage costs. Coal-fired outage costs are amortized on a straight-line basis to expense over periods up to 60 months, depending on the operating cycle of each unit. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 or 24-month operating cycles of each unit.

(d) Prior to Nuclear Regulatory Commission (NRC) approval of a 20-year license extension for Plant Vogtle, we deferred the difference between Plant Vogtle depreciation expense based on the then 40-year operating license and depreciation expense assuming an expected 20-year license extension. Amortization commenced upon NRC approval of the license extension in 2009 and is being amortized over the remaining life of the plant.

(e) Represents the deferral of accelerated depreciation associated with the early retirement of Plant Wansley, which occurred on August 31, 2022. Amortization commenced upon the retirement of Plant Wansley and will end no later than December 31, 2040.

(f) Deferred charges consist of training related costs, including interest and carrying costs of such training. Amortization will commence effective with the commercial operation date of each unit and amortized to expense over the life of the units.

(g) Deferral of premiums paid to purchase interest rate options used to hedge interest rates on certain borrowings, related carrying costs and other incidentals associated with construction of Vogtle Units No. 3 and No. 4. Amortization will commence the earlier of when Vogtle Unit No. 3 is placed in service or December 2023.

(h) Effects on net margin for Smith and Hawk Road Energy Facilities were deferred through the end of 2015 and are being amortized over the remaining life of each respective plant.

(i) Represents the accrual of retirement costs associated with long-lived assets for which there are no legal obligations to retire the assets.

(j) Represents collections for future major maintenance costs; revenues are recognized as major maintenance costs are incurred.

(k) Represents collections to fund certain debt payments to be made through the end of 2025 which will be in excess of amounts collected through depreciation expense; the deferred credits will be amortized over the remaining useful life of the plants.

(l) Represents the difference in the timing of recognition of decommissioning costs for financial statement purposes versus ratemaking purposes, as well as the deferral of unrealized gains and losses of funds set aside for decommissioning.

(m) Deferred revenues under a rate management program that allows for additional collections over a five-year period beginning in 2018. These amounts will be amortized to income and applied to member billings, per each member's election, over the subsequent five-year period.

(n) Represents the deferral of unrealized gains on natural gas contracts.

(o) The amortization periods for other regulatory assets range up to 27 years and the amortization periods of other regulatory liabilities range up to 4 years.

(p) Effects on net margin for the Effingham Energy Facility that are being deferred until on or before January 2026 and will be amortized over the remaining life of the plant.

r. Related parties

We and our 38 members are members of Georgia Transmission. Georgia Transmission provides transmission services to its members for delivery of its members' power purchases from us and other power suppliers. We have entered into an agreement with Georgia Transmission to provide transmission services for third party transactions and for service to our owned facilities. For 2022, 2021, and 2020, we incurred expenses from Georgia Transmission of $40,774,000, $39,677,000 and $37,931,000, respectively.

We, Georgia Transmission and 38 of our members are members of Georgia System Operations. Georgia System Operations operates the system control center and currently provides us system operations services and administrative support services. For 2022, 2021, and 2020, we incurred expenses from Georgia System Operations of $27,416,000, $26,936,000, and $27,104,000, respectively.

s. Other income

Other income includes net revenue from Georgia Transmission and Georgia System Operations for administrative costs, as well as capital credits from investments in associated organizations and other miscellaneous income. In 2021, other income increased due to the recognition of gains on the sale of spare inventory parts from one of our generating facilities.

t. Recently issued or adopted accounting pronouncements

In March 2020, the Financial Accounting Standards Board (FASB) issued "Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting." The amendments in this update apply to all entities that have contracts, hedging relationships, and other transactions that reference London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of reference rate reform. The amendments in this update provide optional expedients and exceptions for applying U.S. GAAP to transactions affected by reference rate reform if certain criteria are met. The expedients and exceptions provided by the amendments in this update do not apply to contract modifications made and hedging relationships entered into or evaluated after December 31, 2022, except for hedging relationships existing as of December 31, 2022, for which an entity has elected certain optional expedients that are retained through the end of the hedging relationship.

In January 2021, the FASB issued "Reference Rate Reform (Topic 848): Scope," to further clarify the scope of the reference rate reform guidance in Topic 848. The amendments in this update refine the scope of Topic 848 to clarify that certain optional expedients and exceptions therein for contract modifications and hedge accounting apply to contracts that are affected by the discounting transition. Specifically, modifications related to reference rate reform would not be considered an event that requires reassessment of previous accounting conclusions. The amendments in this update also amend the expedients and exceptions in Topic 848 to capture the incremental consequences of the scope clarification and to tailor the existing guidance to derivative instruments affected by the discounting transition.

The amendments in these updates were effective for all entities as of March 12, 2020 through December 31, 2022.

In December 2022, the FASB issued "Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848.", that defers the sunset date of Topic 848 from December 31, 2022 to December 31, 2024, after which entities will no longer be permitted to apply the relief in Topic 848.

We have fully completed our evaluation of this new standard. The adoption of this standard on January 1, 2022 did not have a material impact on our consolidated financial statements.

u. Measurement of credit losses on financial instruments

The financial assets we hold that are subject to credit losses (Topic 326) are predominately accounts receivable and certain cash equivalents classified as held-to-maturity debt (e.g. commercial paper). Our receivables are generally due within thirty days or less with a significant portion related to billings to our members. See Note 1f for information regarding our member receivables. Commercial paper issuances we invest in are rated as investment grade and backed by a credit facility. Given our historical experience, the short duration lifetime of these financial assets and the short time horizon over which to consider expectations of future economic conditions, we have assessed that non-collection of the cost basis of these financial assets is remote and we have not recognized an allowance for credit losses.

2. Fair Value:

Authoritative guidance regarding fair value measurements for financial and non-financial assets and liabilities defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles, and expands disclosures about fair value measurements.

The guidance establishes a three-tier fair value hierarchy which prioritizes the inputs used in measuring fair value as follows:

- *Level 1.* Quoted prices from active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Quoted prices in active markets provide the most reliable evidence of fair value and are used to measure fair value whenever available. Level 1 primarily consists of financial instruments that are exchange-traded.

- *Level 2.* Pricing inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 2 primarily consists of financial instruments that are non-exchange-traded but have significant observable inputs.

- *Level 3.* Pricing inputs that include significant inputs which are generally less observable from objective sources. These inputs may include internally developed methodologies that result in management's best estimate of fair value. Level 3 financial instruments are those whose fair value is based on significant unobservable inputs.

Assets and liabilities measured at fair value are based on one or more of the following three valuation techniques:

(1) Market approach. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities (including a business) and deriving fair value based on these inputs.

(2) Income approach. The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

(3) Cost approach. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). This approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset or comparable utility adjusted for obsolescence.

		Fair Value Measurements at Reporting Date Using		
	December 31, 2022	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(dollars in thousands)		
Nuclear decommissioning trust funds:				
Domestic equity	**$ 204,129**	$ 204,129	$ —	$ —
International equity trust	**$ 111,266**	—	111,266	—
Corporate bonds and debt	**$ 60,806**	—	60,788	18
US Treasury securities	**$ 49,775**	49,775	—	—
Mortgage backed securities	**$ 41,210**	—	41,210	—
Domestic mutual funds	**$ 57,348**	57,348	—	—
Federal agency securities	**$ 2,037**	—	2,037	—
Non-US Gov't bonds & private placements	**$ 2,890**	—	2,890	—
International mutual funds	**$ 653**	—	653	—
Other	**$ 10,602**	10,602	—	—
Long-term investments:				
International equity trust	**$ 33,606**	—	33,606	—
Corporate bonds and debt	**$ 10,473**	—	10,473	—
US Treasury securities	**$ 15,488**	15,488	—	—
Mortgage backed securities	**$ 12,113**	—	12,113	—
Domestic mutual funds	**$ 302,302**	302,302	—	—
Treasury STRIPS	**$ 293,281**	—	293,281	—
Non-US Gov't bonds & private placements	**$ 1,976**	—	1,976	—
Other	**$ 240**	240	—	—
Short-term investments: Treasury STRIPS	**$ 61,702**	—	61,702	—
Natural gas swaps	**$ 131,804**	—	131,804	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2021	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(dollars in thousands)			
Nuclear decommissioning trust funds:				
Domestic equity	$ 249,999	$ 249,999	$ —	$ —
International equity trust	$ 140,718	—	140,718	—
Corporate bonds and debt	$ 72,936	—	72,369	567
US Treasury securities	$ 53,321	53,321	—	—
Mortgage backed securities	$ 40,460	—	40,460	—
Domestic mutual funds	$ 75,384	75,384	—	—
Municipal bonds	$ 1,133	—	1,133	—
Federal agency securities	$ 9,608	—	9,608	—
Other	$ 16,351	13,623	2,728	—
Long-term investments:				
International equity trust	$ 35,873	—	35,873	—
Corporate bonds and debt	$ 14,022	—	12,656	1,366
US Treasury securities	$ 15,259	15,259	—	—
Mortgage backed securities	$ 12,021	—	12,021	—
Domestic mutual funds	$ 277,937	277,937	—	—
Federal agency securities	$ 257	—	257	—
Treasury STRIPS	$ 350,532	—	350,532	—
Other	$ 5,478	5,478	—	—
Natural gas swaps	$ 63,994	—	63,994	—

The Level 2 investments above in corporate bonds and debt, federal agency mortgage backed securities, and mortgage backed securities may not be exchange traded. The fair value measurements for these investments are based on a market approach, including the use of observable inputs. Common inputs include reported trades and broker/dealer bid/ask prices. The fair value of the Level 2 investments above in international equity trust are calculated based on the net asset value per share of the fund. There are no unfunded commitments for the international equity trust and redemption may occur daily with a 3-day redemption notice period.

The Level 3 investments above in corporate bonds and debt consist of investments in bank loans which are not exchange traded. Although these securities may be liquid and priced daily, their inputs are not observable.

The estimated fair values of our long-term debt, including current maturities at December 31, 2022 and 2021 were as follows:

	2022		2021	
	(in thousands)			
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 11,940,359**	**$ 10,194,954**	$ 10,915,054	$ 12,741,046

The estimated fair value of long-term debt is classified as Level 2 and is based on observed or quoted market prices for the same or similar issues, or based on current rates offered to us for debt of similar maturities. The primary sources of our long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank that is guaranteed by the Rural Utilities Service or the U.S. Department of Energy. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from a third party data reporting service, and are based on secondary market trading of our debt. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of December 31, 2022 plus an applicable spread, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank.

For cash, cash equivalents, and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments. Restricted investments consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account and the carrying amount of these investments approximates fair value because of the liquid nature of the deposits with the U.S. Treasury.

3. Derivative instruments:

We use commodity derivatives to manage our exposure to fluctuation in the market price of natural gas. Our risk management and compliance committee provides general oversight over all derivative activities. We do not apply hedge accounting to derivative transactions, but instead apply regulated operations accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps are reflected as regulatory assets or liabilities, as appropriate. Realized gains and losses on natural gas swaps are included in fuel expense within our consolidated statements of revenues and expenses and, therefore, net margins within our consolidated statements of cash flows.

We are exposed to credit risk as a result of entering into these arrangements. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. We have established policies and procedures to manage credit risk through counterparty analysis, exposure calculation and monitoring, exposure limits, collateralization and certain other contractual provisions.

It is possible that volatility in commodity prices could cause us to have credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of December 31, 2022 all of the counterparties with transaction amounts outstanding under our derivative programs are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

We have entered into International Swaps and Derivatives Association agreements with our natural gas derivative counterparties that mitigate credit exposure by creating contractual rights relating to creditworthiness, collateral, termination and netting (which, in certain cases, allows us to use the net value of affected transactions with the same counterparty in the event of default by the counterparty or early termination of the agreement).

Additionally, we have implemented procedures to monitor the creditworthiness of our counterparties and to evaluate nonperformance in valuing counterparty positions. We have contracted with a third party to assist in monitoring certain of our counterparties' credit standing and condition. Net liability positions are generally not adjusted as we use derivative transactions as hedges and have the ability and intent to perform under each of our contracts. In the instance of net asset positions, we consider general market conditions and the observable financial health and outlook of specific counterparties, forward looking data such as credit default swaps, when available, and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

The contractual agreements contain provisions that could require us or the counterparty to post collateral or credit support. The amount of collateral or credit support that could be required is calculated as the difference between the aggregate fair value of the hedges and pre-established credit thresholds. The credit thresholds are contingent upon each party's credit ratings from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty.

Under the natural gas swap arrangements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment.

At December 31, 2022 and 2021, the estimated fair values of our natural gas contracts were net assets of $131,804,000 and $63,994,000, respectively.

As of December 31, 2022 and 2021, one of our counterparties was required to post credit collateral totaling $30,400,000 and $1,800,000, respectively, under our natural gas swap agreements. Such posted collateral is classified as restricted cash and included in the Restricted cash and short-term investments line items within our consolidated balance sheets.

The following table reflects the volume activity of our natural gas derivatives as of December 31, 2022 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs)
	(in millions)
2023	32.1
2024	27.7
2025	23.3
2026	18.2
2027	6.0
Total	**107.3**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at December 31, 2022 and 2021.

	Consolidated Balance Sheet Location	Fair Value	
		2022	2021
		(dollars in thousands)	
Assets			
Natural gas swaps	Other current assets	**$ 35,285**	$ 23,596
Natural gas swaps	Other deferred charges	**$ 99,725**	$ 40,398
Liabilities			
Natural gas swaps	Other current liabilities	**$ 3,206**	$ —

The following table presents the realized gains and (losses) on derivative instruments recognized in margin for the years ended December 31, 2022, 2021 and 2020.

	Consolidated Statement of Revenues and Expenses Location	2022	2021	2020
			(dollars in thousands)	
Natural gas swaps gains	Fuel	**$ 121,626**	$ 31,440	$ 830
Natural gas swaps losses	Fuel	**(6,587)**	(1,431)	(21,179)
Total		**$ 115,039**	$ 30,009	$ (20,349)

The following table presents the unrealized (gains) and losses on derivative instruments deferred on the consolidated balance sheets at December 31, 2022 and 2021.

	Consolidated Balance Sheet Location	2022	2021
		(dollars in thousands)	
Natural gas swaps	Regulatory liability	**$ 131,804**	$ 63,994
Total		**$ 131,804**	$ 63,994

4. Investments:

Investments in debt and equity securities

Investment securities we hold are recorded at fair value in the accompanying consolidated balance sheets. We apply regulated operations accounting to the unrealized gains and losses of all investment securities. All realized and unrealized gains and losses are determined using the specific identification method.

The following tables summarize debt and equity securities at December 31, 2022 and 2021.

	(dollars in thousands)			
		Gross Unrealized		
2022	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 323,907**	**$ 159,445**	**$ (8,949)**	**$ 474,403**
Debt	**833,035**	**372**	**(46,369)**	**787,038**
Other	**10,445**	**20**	**(9)**	**10,456**
Total	**$ 1,167,387**	**$ 159,837**	**$ (55,327)**	**$ 1,271,897**

	(dollars in thousands)			
		Gross Unrealized		
2021	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	$ 304,305	$ 280,127	$ (4,682)	$ 579,750
Debt	774,580	4,859	(7,001)	772,438
Other	19,102	—	(1)	19,101
Total	$ 1,097,987	$ 284,986	$ (11,684)	$ 1,371,289

The contractual maturities of debt securities, which are included in the estimated fair value table above, at December 31, 2022 and 2021 are as follows:

	(dollars in thousands)			
	2022		2021	
	Cost	**Fair Value**	Cost	Fair Value
Due within one year	**$ 367,199**	**$ 353,180**	$ 223,933	$ 222,307
Due after one year through five years	**293,523**	**275,073**	371,060	368,574
Due after five years through ten years	**66,255**	**62,576**	62,679	62,639
Due after ten years	**106,058**	**96,209**	116,908	118,918
Total	**$ 833,035**	**$ 787,038**	$ 774,580	$ 772,438

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2022, 2021 and 2020:

	(dollars in thousands)		
	2022	2021	2020
Gross realized gains	**$ 10,029**	$ 33,501	$ 36,647
Gross realized losses	**(31,979)**	(19,985)	(16,868)
Proceeds from sales	**301,128**	913,600	756,513

Investment in associated companies

Investments in associated companies were as follows at December 31, 2022 and 2021:

	(dollars in thousands)	
	2022	2021
National Rural Utilities Cooperative Finance Corporation (CFC)	**$ 24,081**	$ 24,081
CT Parts, LLC	**6,574**	7,049
Georgia Transmission Corporation	**38,287**	35,696
Georgia System Operations Corporation	**7,750**	6,500
Other	**2,245**	2,500
Total	**$ 78,937**	$ 75,826

The CFC investments consist of capital term certificates required in connection with our membership in CFC and a voluntary investment in CFC member capital securities. Accordingly, there is no market for these investments and they are valued at cost. The investment in Georgia Transmission represents capital credits valued at cost. The investment in Georgia System Operations represents loan advances. Repayments of these advances are due by December 2028.

CT Parts, LLC is an affiliated organization formed by us and Smarr EMC for the purpose of purchasing and maintaining spare parts inventory and for the administration of contracted services for combustion turbine generation facilities. Such investment is recorded at cost.

Rocky Mountain transactions

In December 1996 and January 1997, we entered into six long-term lease transactions relating to our 74.61% undivided interest in Rocky Mountain. In each transaction, we leased a portion of our undivided interest in Rocky Mountain to six separate owner trusts for the benefit of three investors, referred to as owner participants, for a term equal to 120% of the estimated useful life of Rocky Mountain. Immediately thereafter, the owner trusts leased their undivided interests in Rocky Mountain to our wholly owned subsidiary, Rocky Mountain Leasing Corporation, or RMLC, for a term of 30 years under six separate leases. RMLC then subleased the undivided interests back to us under six separate leases for an identical term.

In 2012, we terminated five of the six lease transactions prior to the end of their lease terms. The remaining lease in place represented approximately 10% of the original lease transactions. Pursuant to a payment undertaking agreement, we have a guarantee for the annual basic rent payments due under the remaining lease. The fair value amount relating to the guarantee of basic rent payment is immaterial to us principally due to the high credit rating of the payment undertaker, Rabobank Nederland. The basic rental payments remaining through the end of the lease, which expires in 2027, are approximately $19,565,000.

At the end of the term of the remaining facility lease, we have the option to cause RMLC to purchase the owner trust's undivided interest in Rocky Mountain at a fixed purchase option price of approximately $112,000,000. The payment undertaking agreement, along with the equity funding agreement with AIG Matched Funding Corp., would fund approximately $74,000,000 and $37,928,000 of this amount, respectively, and these amounts would be paid to the owner trust over five installments in 2027. If we do not elect to cause RMLC to purchase the owner trust's undivided interest in Rocky Mountain, Georgia Power has an option to purchase the undivided interest. If neither we nor Georgia Power exercise our purchase option, and we return (through RMLC) the undivided interest in Rocky Mountain to the owner trust, the owner trust has several options it can elect, including:

- causing RMLC and us to renew the related facility lease and facility sublease for up to an additional 16 years and provide collateral satisfactory to the owner trust,
- leasing its undivided interest to a third party under a replacement lease, or
- retaining the undivided interest for its own benefit.

Under the first two of these options we must arrange new financing for the outstanding amount of the loan used to finance the owner trust's upfront rental payment made to us when the lease closed on December 31, 1996. At the end of the lease term, the amount of the outstanding loan is anticipated to be approximately $74,000,000. If new financing cannot be arranged, the owner trust can ultimately cause us to purchase 49%, in the case of the first option above, or all, in the case of the second option above, of the loan certificate or cause RMLC to exercise its purchase option or RMLC to renew the facility lease and facility sublease, respectively.

The assets of RMLC are not available to pay our creditors.

5. Income taxes:

While we are a not-for-profit membership corporation formed under the laws of the state of Georgia, we are subject to federal and state income taxation. As a taxable cooperative, we are allowed to deduct patronage dividends that we allocate to our members for purposes of calculating our taxable income. We annually allocate income and deductions between patronage and non-patronage activities and substantially all of our income is from patronage-sourced activities, resulting in no current period income tax expense or current or deferred income tax liability.

Although we believe that treatment of non-member sales as patronage-sourced income is appropriate, this treatment has not been examined by the Internal Revenue Service. If this treatment was not sustained, we believe that the amount of taxes on such non-member sales, after allocating related expenses against the revenues from such sales, would not have a material adverse effect on our financial condition or results of operations and cash flows.

We account for income taxes pursuant to the authoritative guidance for accounting for income taxes, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns.

The difference between the statutory federal income tax rate on income before income taxes and our effective income tax rate is summarized as follows:

	2022	2021	2020
Statutory federal income tax rate	**21.0 %**	21.0 %	21.0 %
Patronage exclusion	**(21.0)%**	(21.0)%	(21.0)%
Effective income tax rate	**0.0 %**	0.0 %	0.0 %

The components of our net deferred tax assets and liabilities as of December 31, 2022 and 2021 were as follows:

	(dollars in thousands)	
	2022	2021
Deferred tax assets		
Net operating losses	**$ 115,080**	$ —
Obligation related to asset retirements	**345,879**	331,311
Advance payments	**183,833**	175,077
Other regulatory liabilities	**18,687**	54,611
Other assets	**30,373**	24,838
Deferred tax assets	**693,852**	585,837
Less: Valuation allowance	**—**	—
Net deferred tax assets	**$ 693,852**	$ 585,837
Deferred tax liabilities		
Fixed assets and intangibles	**$ (140,095)**	$ (40,655)
Right-of-use assets-finance leases	**(77,923)**	(77,923)
Other regulatory asset	**(343,230)**	(338,291)
Other liabilities	**(15,352)**	(17,984)
Deferred tax liabilities	**(576,600)**	(474,853)
Net deferred tax assets (liabilities)	**$ 117,252**	$ 110,984
Less: Patronage exclusion	**(117,252)**	(110,984)
Net deferred taxes	**$ —**	$ —

As of December 31, 2022, we generated a current year federal net operating loss of $447,086,000 which may be carried forward indefinitely. Due to the tax basis method for allocating patronage dividends, we will utilize this loss to offset any future federal taxable income prior to member allocation per the bylaws. There is no net impact to the deferred tax asset after the patronage exclusion.

The authoritative guidance for income taxes addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. We may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

We file a U.S. federal consolidated income tax return. The U.S. federal statute of limitations remains open for the year 2019 and forward. State jurisdictions have statutes of limitations generally ranging from three to five years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by tax authorities in major state jurisdictions include 2019 and forward. We have no liabilities recorded for uncertain tax positions.

6. Leases:

As a lessee, we have a relatively small portfolio of leases with the most significant being our 60% undivided interest in Scherer Unit No. 2 and railcar leases for the transportation of coal. We also have various other leases of minimal value.

We classify our four Scherer Unit No. 2 leases as finance leases and our railcar leases as operating leases. We have made an accounting policy election not to recognize right-of-use assets and lease liabilities that arise from short-term leases, leases having an initial term of 12 months or less, for any class of underlying asset. We recognize lease expense for short-term leases on a straight-line basis over the lease term. Lease expense recognized for our short-term leases during 2022 and 2021 was insignificant.

Finance Leases

Three of our Scherer Unit No. 2 finance leases have lease terms through December 31, 2027, and one lease extends through June 30, 2031. At the end of the leases, we can elect at our sole discretion to:

- Renew the leases for a period of not less than one year and not more than five years at fair market value,
- Purchase the undivided interest at fair market value, or
- Redeliver the undivided interest to the lessors.

For rate-making purposes, we include the actual lease payments for our finance leases in our cost of service. The difference between lease payments and the aggregate of the amortization on the right-of-use asset and the interest on the finance lease obligation is recognized as a regulatory asset. Finance lease amortization is recorded in depreciation and amortization expense.

Operating Leases

Our railcar operating leases have terms that extend through October 31, 2026. At the end of the railcar operating leases, we can renew at terms mutually agreeable by us and the lessors, purchase the assets or return the assets to the lessors. We have an additional operating lease that has a term that extends through February 2042 with one renewal option for a 20-year term.

The exercise of renewal options for our finance and operating leases is at our sole discretion.

As all of our operating leases do not provide an implicit rate, we used our incremental borrowing rate based on the information available at the time new lease agreements are entered into or reassessed to determine the present value of lease payments.

For lease agreements entered into or reassessed after the adoption of the new leases standard, we combine lease and nonlease components.

Classification	**2022**	2021
	(dollars in thousands)	
Right-of-use assets - Finance leases		
Right-of-use assets	**$ 302,732**	$ 302,732
Less: Accumulated provision for depreciation	**(272,876)**	(267,606)
Total finance lease assets	**$ 29,856**	$ 35,126
Lease liabilities - Finance leases		
Obligations under finance leases	**$ 52,937**	$ 61,335
Long-term debt and finance leases due within one year	**8,398**	7,541
Total finance lease liabilities	**$ 61,335**	$ 68,876

Classification	**2022**	2021
	(dollars in thousands)	
Right-of-use assets - Operating leases		
Electric plant in service, net	**$ 3,326**	$ 2,293
Total operating lease assets	**$ 3,326**	$ 2,293
Lease liabilities - Operating leases		
Capitalization - Other	**$ 2,256**	$ 1,550
Other current liabilities	**1,164**	838
Total operating lease liabilities	**$ 3,420**	$ 2,388

Lease Cost	Classification		2022		2021
			(dollars in thousands)		
Finance lease cost:					
Amortization of leased assets	Depreciation and amortization	**$**	**7,542**	$	6,420
Interest on lease liabilities	Interest expense	**$**	**7,408**	$	8,177
Operating lease cost	Inventory(1) & production expense	**$**	**995**	$	1,079
Total lease cost		**$**	**15,945**	$	15,676

[(1)]The majority of our operating lease costs relate to our railcar leases and such costs are added to the cost of our fossil-fuel inventories and are recognized in fuel expense as the inventories are consumed.

	December 31, 2022	December 31, 2021
Lease Term and Discount Rate		
Weighted-average remaining lease term (in years):		
Finance leases	**5.94**	6.90
Operating leases	**6.44**	8.01
Weighted-average discount rate:		
Finance leases	**11.05 %**	11.05 %
Operating leases	**5.52 %**	4.73 %

		2022		2021
		(dollars in thousands)		
Other Information:				
Cash paid for amounts included in the measurement of lease liabilities				
Operating cash flows from finance leases	**$**	**7,408**	$	8,177
Operating cash flows from operating leases	**$**	**1,009**	$	1,129
Financing cash flows from finance leases	**$**	**7,541**	$	6,772
Right-of-use assets obtained in exchange for new operating lease liabilities	**$**	**1,954**	$	—

Maturity analysis of our finance and operating lease liabilities as of December 31, 2022 is as follows:

	(dollars in thousands)		
Year Ending December 31,	Finance Leases	Operating Leases	Total
2023	$ 14,949	$ 1,324	$ 16,273
2024	14,949	850	15,799
2025	14,949	641	15,590
2026	14,949	350	15,299
2027	14,949	72	15,021
Thereafter	10,683	868	11,551
Total lease payments	$ 85,428	$ 4,105	$ 89,533
Less: imputed interest	(24,093)	(685)	(24,778)
Present value of lease liabilities	$ 61,335	$ 3,420	$ 64,755

As a lessor, we primarily lease office space to several tenants within our headquarters building. Several of these tenants are related parties. We account for all of these lease agreements as operating leases.

Lease income recognized during 2022 and 2021 was as follows:

	2022	2021
Lease income	**$6,539**	$6,312

7. Debt:

Long-term debt consists of first mortgage notes payable to the United States of America acting through the Federal Financing Bank (FFB) and guaranteed by the Rural Utilities Service or the U.S. Department of Energy, first mortgage bonds payable (FMBs) and first mortgage notes issued in conjunction with the sale by public authorities of pollution control revenue bonds (PCRBs). Substantially all of our owned tangible and certain of our intangible assets are pledged under our first mortgage indenture as collateral for the Federal Financing Bank notes, the first mortgage bonds, and the first mortgage notes issued in conjunction with the sale of pollution control revenue bonds.

Maturities for long-term debt and finance lease obligations through 2027 are as follows:

	(dollars in thousands)				
	2023	2024	2025	2026	2027
FFB	$ 312,695	$ 308,892	$ 282,399	$ 262,793	$ 271,623
FMBs	1,010	63,510	62,500	62,500	62,500
PCRBs	—	—	—	—	—
	$ 313,705	$ 372,402	$ 344,899	$ 325,293	$ 334,123
Finance Leases	8,398	9,351	10,413	11,595	12,912
Total	$ 322,103	$ 381,753	$ 355,312	$ 336,888	$ 347,035

The weighted average interest rate on our long-term debt at December 31, 2022 and 2021 was 3.78% and 3.69%, respectively.

Long-term debt outstanding and the associated unamortized debt issuance costs and debt discounts at December 31, 2022 and December 31, 2021 are as follows:

	2022		2021	
	Principal	**Unamortized Debt Issuance Costs and Debt Discounts**	Principal	Unamortized Debt Issuance Costs and Debt Discounts
	(dollars in thousands)			
FFB	**$ 7,084,148**	**$ 52,690**	$ 6,526,858	$ 55,159
FMBs	**4,152,021**	**52,480**	3,653,031	46,985
PCRBs	**704,190**	**8,972**	735,165	9,765
	$ 11,940,359	**$ 114,142**	$ 10,915,054	$ 111,909

We use the effective interest rate method to amortize debt issuance costs and debt discounts as well as the straight-line method when the results approximate those of the effective interest rate method. Unamortized debt issuance costs and debt discounts are being amortized to expense over the life of the respective debt issues.

a) *Department of Energy Loan Guarantee:*

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005, we and the U.S. Department of Energy, acting by and through the Secretary of Energy, entered into a Loan Guarantee Agreement on February 20, 2014 pursuant to which the Department of Energy agreed to guarantee our obligations under a Note Purchase Agreement, dated as of February 20, 2014 (the Original Note Purchase Agreement), among us, the Federal Financing Bank and the Department of Energy and two future advance promissory notes, each dated February 20, 2014, made by us to the Federal Financing Bank in the aggregate amount of $3,057,069,461 (the Original FFB Notes and together with the Original Note Purchase Agreement, the Original FFB Documents).

On March 22, 2019, we and the Department of Energy entered into an Amended and Restated Loan Guarantee Agreement (as amended, the Loan Guarantee Agreement) which increased the aggregate amount guaranteed by the Department of Energy to $4,676,749,167. We also entered into a Note Purchase Agreement dated as of March 22, 2019 (the Additional Note Purchase Agreement), among us, the Federal Financing Bank and the Department of Energy and a future advance promissory note, dated March 22, 2019, made by us to the Federal Financing Bank in the amount of $1,619,679,706 (the Additional FFB Note and together with the Additional Note Purchase Agreement, the Additional FFB Documents).

Together, the Original FFB Documents and Additional FFB Documents provide for a multi-advance term loan facility (the Facility) under which we may make long-term loan borrowings through the Federal Financing Bank.

Proceeds of advances made under the Facility are used to reimburse us for a portion of certain costs of construction relating to Vogtle Units No. 3 and No. 4 that are eligible for financing under the Title XVII loan guarantee program (Eligible Project Costs). Borrowings under the Original FFB Notes could not exceed $3,057,069,461, of which $335,471,604 was designated for capitalized interest. We have advanced all amounts available under the Original FFB Notes. We were unable to advance $43,721,079 of the amount designated for capitalized interest under the Original FFB Notes due to the timing of borrowing and lower than expected interest rates.

Borrowings under the Additional FFB Note may not exceed (i) $1,619,679,706 or (ii) an amount that, when aggregated with borrowings under the Original FFB Notes, equals 70% of Eligible Project Costs less the $1,104,000,000 guarantee payment we received from Toshiba Corporation in late 2017. At December 31, 2022, borrowings under the Additional FFB Note totaled $1,619,679,706.

At December 31, 2022, we had borrowed a total of $4,633,028,088, including capitalized interest under the Department of Energy-guaranteed loans. As of December 31, 2022, we have fully advanced under these guaranteed loans.

Under the Loan Guarantee Agreement, we are obligated to reimburse the Department of Energy in the event it is required to make any payments to the Federal Financing Bank under its guarantee. Our payment obligations to the Federal Financing Bank under the FFB Notes and reimbursement obligations to the Department of Energy under its guarantee, but not our covenants to the Department of Energy under the Loan Guarantee Agreement, are secured equally and ratably with all of our other obligations issued under our first mortgage indenture. The final maturity date for each advance is February 20, 2044. Interest is payable quarterly in arrears and principal payments on all advances under the FFB Notes began on February 20, 2020. As of December 31, 2022, we have repaid $307,600,000 of principal borrowed on the FFB Notes. Interest rates on advances during the applicable interest rate periods will equal the current average yield on U.S. Treasuries of comparable maturity at the beginning of the interest rate period, plus a spread equal to 0.375%.

We may voluntarily prepay outstanding borrowings under the Facility. Under the FFB Documents, any prepayment will be subject to a make-whole premium or discount, as applicable. Any amounts prepaid may not be re-borrowed.

Under the Loan Guarantee Agreement, we are subject to customary borrower affirmative and negative covenants and events of default. In addition, we are subject to project-related reporting requirements and other project-specific covenants and events of default.

If certain events occur, referred to as an "Alternate Amortization Event," at the Department of Energy's option the Federal Financing Bank's commitment to make further advances under the Facility will terminate and we will be required to repay the outstanding principal amount of all borrowings under the Facility over a period of five years, with level principal amortization. These events include (i) abandonment of the Vogtle Units No. 3 and No. 4 project, including a decision by Georgia Power to cancel the project, (ii) cessation of the construction of Vogtle Units No. 3 and No. 4 for twelve consecutive months, (iii) termination of the Services Agreement or rejection of the Services Agreement in bankruptcy, if Georgia Power does not maintain access to certain related intellectual property rights, (iv) termination of the Services Agreement by Westinghouse or termination of the Bechtel Agreement by Bechtel Power Corporation, (v) delivery of certain notices by the Co-owners to the Department of Energy of their intent to cancel construction of Vogtle Units No. 3 and No. 4 coupled with termination by the Co-owners of the Services Agreement or the Bechtel Agreement, (vi) failure of the Co-owners to enter into a replacement contract with respect to the Services Agreement or the Bechtel Agreement following the Co-owners' termination of such agreement with the intent to replace it, (vii) the Department of Energy's takeover of construction of Vogtle Units No. 3 and No. 4 under certain conditions, (viii) the occurrence of any Project Adverse Event that results in a cancellation of the Vogtle Units No. 3 and No. 4 project or the cessation or deferral of construction beyond the periods permitted under the Loan Guarantee Amendment, (ix) loss of or failure to receive necessary regulatory approvals under certain circumstances, (x) loss of access to intellectual property rights necessary to construct or operate Vogtle Units No. 3 and No. 4 under certain circumstances, (xi) our failure to fund our share of operation and maintenance expenses for Vogtle Units No. 3 and No. 4 for twelve consecutive months, (xii) change of control of Oglethorpe and (xiii) certain events of loss or condemnation. If we receive proceeds from an event of condemnation relating to Vogtle Units No. 3 and No. 4, such proceeds must be applied to immediately prepay outstanding borrowings under the Facility.

b) *Rural Utilities Service Guaranteed Loans:*

During 2022, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $317,245,000 for long-term financing of general and environmental improvements at existing plants and the Effingham acquisition. This total includes a Rural Utilities Service-guaranteed loan that provided long-term funding for the Effingham acquisition in the amount of $234,681,000 that closed in October 2022 and was fully advanced in November 2022.

In January 2023, we received an additional $15,431,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

c) Credit Facilities:

As of December 31, 2022, we had a total of $1,810,000,000 of committed credit arrangements comprised of four separate facilities with maturity dates that range from December 2023 to December 2024. These credit facilities are for general working capital purposes, issuing letters of credit and backing up outstanding commercial paper. Under our unsecured committed lines of credit that we had in place at December 31, 2022, we had the ability to issue letters of credit totaling $960,000,000 in the aggregate, of which $957,000,000 remained available. At December 31, 2022, we had (i) $2,504,000 under these lines of credit in the form of issued letters of credit and (ii) $659,000,000 dedicated under one of these lines of credit to support a like amount of commercial paper that was outstanding.

d) First Mortgage Bonds:

On April 12, 2022, we issued $500,000,000 of 4.50% first mortgage bonds, Series 2022A, for the purpose of providing long-term financing for expenditures related to the construction of Vogtle Units No. 3 and No. 4. In conjunction with the issuance of the bonds, we repaid $493,405,000 of outstanding commercial paper. The bonds are due to mature April 2047 and are secured under our first mortgage indenture.

e) Pollution Control Revenue Bonds:

On September 9, 2022, we redeemed $30,975,000 of Series 2017 pollution control revenue bonds.

On February 1, 2023, we remarketed $99,785,000 of Series 2017 pollution control revenue bonds. The remarketed bonds bear interest at indexed put rate modes until February 1, 2028 and are scheduled to mature in 2045. Our payment obligations related to these bonds are secured under our first mortgage indenture.

8. Electric plant, construction and related agreements:

a. Electric plant

We, along with Georgia Power, have entered into agreements providing for the purchase and subsequent joint operation of certain electric generating plants. Each co-owner is responsible for providing their own financing. The plant investments disclosed in the table below represent our undivided interest in each plant. A summary of our plant investments and related accumulated depreciation as of December 31, 2022 and 2021 is as follows:

	2022		2021	
	(dollars in thousands)			
Plant	**Investment**	**Accumulated Depreciation**	Investment	Accumulated Depreciation
In-service[1]				
Owned property				
Vogtle Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**$ 3,024,112**	**$ (1,916,942)**	$ 3,010,843	$ (1,881,324)
Vogtle Units No. 3 & No. 4 *(Nuclear – 30% ownership)*	**58,189**	**(8,627)**	58,199	(7,290)
Hatch Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**991,852**	**(533,771)**	973,682	(503,871)
Wansley Units No. 1 & No. 2[2] *(Fossil – 30% ownership)*	**20,312**	**(15,337)**	820,110	(649,301)
Scherer Unit No. 1 *(Fossil – 60% ownership)*	**1,378,904**	**(636,799)**	1,415,115	(638,443)
Doyle *(Combustion Turbine - 100% ownership)*	**145,780**	**(124,306)**	144,711	(120,527)
Rocky Mountain Units No. 1, No. 2 & No. 3 *(Hydro – 75% ownership)*	**616,278**	**(296,624)**	615,485	(284,749)
Hartwell *(Combustion Turbine - 100% ownership)*	**232,532**	**(125,092)**	227,834	(121,174)
Hawk Road *(Combustion Turbine - 100% ownership)*	**269,837**	**(74,685)**	266,149	(69,194)
Talbot *(Combustion Turbine - 100% ownership)*	**301,869**	**(162,137)**	300,335	(158,270)
Chattahoochee *(Combined cycle - 100% ownership)*	**324,310**	**(171,272)**	319,550	(166,859)
Effingham *(Combined cycle - 100% ownership)*	**339,189**	**(121,318)**	337,614	(112,057)
Smith *(Combined cycle - 100% ownership)*	**686,517**	**(208,142)**	672,184	(190,760)
Wansley *(Combustion Turbine – 30% ownership)*[2]	**—**	**—**	3,942	(3,889)
Washington County *(Combustion Turbine – 100% ownership)*	**170,432**	**(88,585)**	—	—
Transmission plant	**107,992**	**(64,785)**	102,966	(62,457)
Other	**106,424**	**(65,922)**	104,372	(62,885)
Property under finance lease:				
Scherer Unit No. 2 *(Fossil – 60% leasehold)*	**794,830**	**(569,245)**	795,301	(532,674)
Total in-service	**$ 9,569,359**	**$ (5,183,589)**	$ 10,168,392	$ (5,565,724)
Construction work in progress				

Vogtle Units No. 3 & No. 4	$	**7,583,291**	$	6,680,014
Environmental and other generation improvements		**132,744**		99,378
Total construction work in progress	$	**7,716,035**	$	6,779,392

(1) Amounts include plant acquisition adjustments at December 31, 2022 of $280,396,000 and December 31, 2021 of $248,000,000.

(2) Plant Wansley Units No. 1 and No. 2 and the combustion turbine were retired on August 31, 2022. The remaining balance represents land and certain asset retirement obligations.

Our proportionate share of direct expenses of joint operation of the above plants is included in the corresponding operating expense captions (e.g., fuel, production) on the accompanying consolidated statements of revenues and expenses.

b. Construction

Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units under construction at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company, Inc. as its agent for licensing, engineering, procurement, contract management, construction and pre-operation services.

In 2008, Georgia Power, acting for itself and as agent for the Co-owners, entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with Westinghouse Electric Company LLC and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (collectively, Westinghouse). Pursuant to the EPC Agreement, Westinghouse agreed to design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle.

Until March 2017, construction on Units No. 3 and No. 4 continued under the substantially fixed price EPC Agreement. In March 2017, Westinghouse filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Effective in July 2017, Georgia Power, acting for itself and as agent for the other Co-owners, and Westinghouse entered into a services agreement (the Services Agreement), pursuant to which Westinghouse is providing facility design and engineering services, procurement and technical support and staff augmentation on a time and materials cost basis. The Services Agreement provides that it will continue until the start-up and testing of Vogtle Units No. 3 and No. 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Co-owners upon 30 days' written notice.

In October 2017, Georgia Power, acting for itself and as agent for the other Co-owners, entered into a construction completion agreement with Bechtel Power Corporation, pursuant to which Bechtel serves as the primary contractor for the remaining construction activities for Vogtle Units No. 3 and No. 4 (the Bechtel Agreement) and is reimbursed for actual costs plus a base fee and an at-risk fee, subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Co-owner is severally, and not jointly, liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Co-owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Co-owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Co-owner suspensions of work, certain breaches of the Bechtel Agreement by the Co-owners, Co-owner insolvency and certain other events.

Cost and Schedule

Our current budget for our ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs, allowance for funds used during construction and some level of contingency is $8.1 billion and is based on commercial operation dates of June 2023 and March 2024 for Units No. 3 and No. 4, respectively. This budget reflects our June 17, 2022 exercise of the tender option in the Global Amendments to the Joint Ownership Agreements as described below. Had we not exercised the tender option, our budget would be approximately $8.65 billion. At December 31, 2022, our total investment for our interest in the additional Vogtle units was approximately $8.0 billion. We and some of our members have implemented various rate management programs to lessen the impact on rates when Vogtle Units No. 3 and No. 4 reach commercial operation.

Our initial ownership interest and proportionate share of the cost to construct the additional Vogtle units was 30%, representing approximately 660 megawatts. However, we have exercised the tender option discussed below which caps our capital costs in exchange for a proportionate reduction of our 30% interest in the two units. Based on the current project budget and schedule and our interpretation of the Global Amendments (described below), we would transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share would decline from 30% to approximately 27.5%. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced.

The table below shows our project budget and actual costs through December 31, 2022 for our share of the project.

(in millions)	Project Budget (Tender)	Actual Costs at December 31, 2022
Construction Costs [1]	$ 6,554	$ 6,147
Freeze Capital Credit [2]	(528)	—
Financing Costs	2,025	1,770
Subtotal	$ 8,051	$ 7,917
Deferred Training Costs	47	46
Total Project Costs Before Contingency	$ 8,098	$ 7,963
Oglethorpe Contingency	$ 2	$ —
Totals	$ 8,100	$ 7,963

[1] Construction costs are net of $1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and $99 million in cost sharing benefits associated with the Global Amendments to the Joint Ownership Agreements.

[2] As described below, we exercised the tender option to cap our capital costs at the EAC in VCM 19 plus $2.1 billion, the freeze tender threshold. The freeze capital credit reflects our share of budgeted amounts that exceed this threshold.

The Oglethorpe-level contingency, which we have carried at various levels since the beginning of the project, provides additional margin to cover potential cost, schedule, and financing risks associated with our share of the project. At the end of the project, if there is remaining Oglethorpe-level contingency, we will adjust our project budget to remove this contingency and bill our members based on the actual project costs. Any schedule extension beyond June 2023 and March 2024 for Units No. 3 and No. 4, respectively, is expected to increase our financing costs by approximately $30 million per month for both units and approximately $13 million per month for Unit No. 4.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts on a regular basis to incorporate current information available, particularly in the areas of start-up testing and related test results, engineering support, commodity installation, system turnovers and workforce statistics.

Since March 2020, the number of active cases of COVID-19 at the site has fluctuated consistent with the surrounding area and impacted productivity levels and pace of activity completion. As of December 31, 2022, the incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity, substantially all of which occurred during 2020 and 2021, is estimated by Georgia Power to be between $350 million and $438 million and is included in the project budget. Future COVID-19 variants could further disrupt or delay construction, testing, supervisory, and support activities at Vogtle Units No. 3 and No. 4.

On July 29, 2022, Southern Nuclear announced that all Unit No. 3 inspections, tests, analyses, and acceptance criteria documentation had been submitted to the Nuclear Regulatory Commission. On August 3, 2022, the Nuclear Regulatory Commission published its 103(g) finding that the acceptance criteria in the combined license for Unit No. 3 had been met, which allowed for nuclear fuel to be loaded and start-up testing to begin. Fuel load for Unit No. 3 was completed on October

17, 2022. In early 2023, during the start-up and pre-operational testing for Unit No. 3, Southern Nuclear identified and remediated certain equipment and component issues. On March 6, 2023, the Unit No. 3 nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality, a key milestone in the start-up process. Georgia Power has disclosed that it projects an in-service date for Unit No. 3 during May or June of 2023. Our current budget reflects our expectation of an in-service date for Unit No. 3 in June 2023. The projected schedule for Unit No. 3 primarily depends on the progression of final component and pre-operational testing and start-up, which may be impacted by further equipment, component and/or other operational challenges.

Georgia Power has disclosed that it projects an in-service date for Unit No. 4 during late fourth quarter 2023 or during the first quarter 2024. Given the remaining work to be done and potential risks associated with completing the work, our current budget anticipates an in-service date for Unit No. 4 in March 2024. Meeting the projected in-service date for Unit No. 4 primarily depends on potential impacts arising from Unit No. 4 testing activities overlapping with Unit No. 3 start-up and commissioning; maintaining overall construction productivity and production levels improving, particularly in subcontractor scopes of work; and maintaining appropriate levels of craft laborers. As Unit No. 4 completes construction and transitions further into testing, ongoing and potential future challenges include the duration of hot functional testing, which commenced on March 20, 2023, and other testing, the pace and quality of remaining commodities installation; completion of documentation to support inspections, tests, analyses and acceptance criteria submittals; the pace of remaining work package closures and system turnovers; and availability of craft, supervisory and technical support resources.

Ongoing or future challenges for both units also include management of contractors and vendors; subcontractor performance; and/or related cost escalation. New challenges also may continue to arise, as Unit No. 3 completes start-up and commissioning and Unit No. 4 moves further into testing and startup, which may result in required engineering changes or remediation related to plant systems, structures or components (some of which are based on new technology that only within the last few years began initial operation in the global nuclear industry at this scale). These challenges may result in further schedule delays and/or cost increases.

There have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to ensure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction.

With the receipt of the Nuclear Regulatory Commission’s 103(g) finding, Unit No. 3 is now under the Nuclear Regulatory Commission’s operating reactor oversight process and must meet applicable technical and operational requirements contained within its operating license. Various design and other licensing-based compliance matters, including the timely submittal by Southern Nuclear of the inspections, tests, analyses, and acceptance criteria documentation and the related reviews and approvals by the Nuclear Regulatory Commission necessary to support authorization to load fuel for Unit No. 4, may arise, which may result in additional license amendment requests or require other resolution. If any license amendment requests or other licensing-based compliance issues, including inspections, tests, analyses, and acceptance criteria for Unit No. 4, are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

The ultimate outcome of these matters cannot be determined at this time.

Co-Owner Contracts and Other Information

In November 2017, the Co-owners entered into an amendment to their joint ownership agreements for Vogtle Units No. 3 and No. 4 to provide for, among other conditions, additional Co-owner approval requirements. These joint ownership agreements, including the Co-owner approval requirements, were subsequently amended, effective August 31, 2018. As described below, certain provisions of the Joint Ownership Agreements were modified further on September 26, 2018 by the Term Sheet that was memorialized on February 18, 2019 when the Co-owners entered into certain amendments (the Global Amendments) to the Joint Ownership Agreements (as amended, the Joint Ownership Agreements).

As a result of an increase in the total project capital cost forecast and Georgia Power’s decision not to seek recovery of its allocation of the increase in the base capital costs and the increased construction budget in connection with Georgia Power’s nineteenth Vogtle construction monitoring report (VCM 19) in 2018, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 were required to vote to continue construction. In September 2018, the Co-owners unanimously voted to continue construction of Vogtle Units No. 3 and No. 4.

In connection with the September 2018 vote to continue construction, Georgia Power entered into a binding term sheet with the other Co-owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, and MEAG Power SPVP, LLC to mitigate certain financial exposure for the other Co-owners and offered to purchase production tax credits from each of the other Co-Owners, at that Co-owner's option (the Term Sheet). On February 18, 2019, the Co-owners entered into the Global Amendments to memorialize the provisions of the Term Sheet. Pursuant to the Global Amendments and consistent with the Term Sheet, the Joint Ownership Agreements provide that:

- each Co-owner is obligated to pay its proportionate share of construction costs for Vogtle Units No. 3 and No. 4 based on its ownership interest up to (i) the estimated cost at completion ("EAC") for Vogtle Units No. 3 and No. 4 which formed the basis of Georgia Power's forecast of $8.4 billion in Georgia Power's VCM 19 report filed with the Georgia Public Service Commission plus (ii) $800 million of additional construction costs.

- Georgia Power will be responsible for 55.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $800 million to $1.6 billion (resulting in up to $80 million of potential additional costs to Georgia Power which would save Oglethorpe up to $44 million), with the remaining Co-owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests (equal to 24.5% for our 30% ownership interest); and

- Georgia Power will be responsible for 65.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $1.6 billion to $2.1 billion (resulting in up to a further $100 million of potential additional costs to Georgia Power which would save Oglethorpe up to an additional $55 million), with the remaining Co-owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests (equal to 19.0% for our 30% ownership interest).

If the EAC is revised and exceeds the EAC in VCM 19 by more than $2.1 billion, each of the Co-owners, other than Georgia Power, has a one-time option to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Co-owner's share of construction costs actually incurred in excess of the EAC in VCM 19 plus $2.1 billion. If any Co-owner elects to exercise this tender option, Georgia Power would have the option to cancel the project in lieu of accepting the offer to purchase a portion of the Co-owner's ownership interest. If Georgia Power does not elect to cancel the project, then Georgia Power must accept the offer, and the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the percentage of the cumulative amount of construction costs paid by such tendering Co-owner as of the commercial operation date of Vogtle Unit No. 4. For purposes of this calculation, payments made by Georgia Power on behalf of the tendering Co-owner in accordance with the second and third bullets above will be treated as payments made by that Co-owner. This option to tender a portion of our interest to Georgia Power upon such a budget increase would allow us to freeze our construction budget associated with the Vogtle project in exchange for a proportionate reduction of our 30% ownership interest.

The VCM 19 total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. As of December 31, 2021, budget increases since VCM 19 reached $3.4 billion for all Co-owners. As a result of those increases, we believe that the tender option was triggered at the Co-owner construction budget vote on February 14, 2022 and that Georgia Power's increased responsibility for certain construction costs as described above commenced in March 2022.

On June 17, 2022, we notified Georgia Power of our election to exercise the tender option and cap our capital costs in exchange for a proportionate reduction of our 30% interest in the two new units. Our decremental ownership interest will be calculated and conveyed to Georgia Power after both Vogtle units are placed in service. Based on the current project budget, our schedule assumptions and our interpretation of the Global Amendments, our project budget is $8.1 billion and we expect to transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share will decline from 30% to approximately 27.5%. By exercising the tender option and based on current assumptions, we estimate that we will avoid incurring approximately $530 million in construction costs associated with the project. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced. On July 26, 2022, the City of Dalton notified Georgia Power that it had elected to exercise its tender option.

We and Georgia Power do not agree on certain aspects of the tender option, including the dollar amount that triggers our option to tender a portion of our ownership interest to Georgia Power under the tender option or the extent to which costs that are the result of a force majeure event (such as COVID-19) impact the point at which the tender option is triggered. For purposes of determining when our option to tender has been triggered, the Global Amendments do not exclude costs resulting from force majeure events (such as COVID-19) from the calculation of when the EAC in VCM 19 plus $2.1 billion has been reached. We and Georgia Power also do not agree on the dollar amount that triggers Georgia Power’s increased responsibility for certain construction costs as described above, and the extent to which costs that are the result of a force majeure event (such as COVID-19), impact the calculation of the point at which Georgia Power’s increased responsibility for certain construction costs as described above is triggered. The exclusion of costs resulting from a force majeure event (such as COVID-19) in the Global Amendments only applies to Georgia Power’s increased cost responsibility during the time period when construction costs exceed the EAC in VCM 19 by $800 million to $2.1 billion.

Accordingly, in March 2022, we notified Georgia Power of a billing dispute with regards to both the starting dollar amount and the application of costs resulting from a force majeure event and how such amounts impact the thresholds and timing of the cost-sharing and tender option provisions. On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County, Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim against us seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power’s related financial obligations. Based on the current project budget and Georgia Power’s interpretation of the Global Amendments, our project budget would be $8.65 billion, and we would incur approximately $530 million of additional construction costs (excluding related financing costs) and retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

Pursuant to the Joint Ownership Agreements, as amended by the Global Amendments, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Global Amendment provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more from the seventeenth VCM report estimated in-service dates of November 2021 and November 2022 for Units No. 3 and No. 4, respectively (each a Project Adverse Event). The schedule extensions, announced in February 2022, which reflected a cumulative delay of over a year for each unit from the schedules approved in the seventeenth VCM report, triggered the requirement for the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 to vote to continue construction, and the Co-owners unanimously voted to continue construction.

The Global Amendments provide that Georgia Power may cancel the project at any time at its sole discretion. In the event that Georgia Power determines to cancel the project or fewer than 90% of the Co-owners vote to continue construction upon the occurrence of a subsequent project adverse event, we and the other Co-owners would assess our options for the Vogtle project. If the investment were to be written off, we would seek regulatory accounting treatment to amortize the investment over a long-term period, which requires the approval of our board of directors, and we would submit the regulatory accounting treatment details to the Rural Utilities Service for its approval. Further, if Georgia Power or the Co-owners decided to cancel the project, the Department of Energy would have the discretion to require that we repay all amounts outstanding under our loan guarantee agreement with the Department of Energy over a five-year period as discussed in Note 7.

The ultimate outcome of these matters cannot be determined at this time.

9. Employee benefit plans:

Our retirement plan is a contributory 401(k) that covers substantially all employees. An employee may contribute, subject to IRS limitations, up to 60% of his or her eligible annual compensation. At our discretion, we may match the employee's contribution and have done so each year of the plan's existence. The match, which is calculated each pay period, currently can be equal to as much as three-quarters of the first 6% of an employee's eligible compensation, depending on the amount and timing of the employee's contribution. Our contributions to the matching feature of the plan were approximately $2,017,000, $1,811,000 and $1,716,000 in 2022, 2021 and 2020, respectively.

Our 401(k) plan also includes an employer retirement contribution feature, which subject to IRS limitations, contributes 11% of an employee's eligible annual compensation. Our contributions to the employer retirement contribution feature of the 401(k) plan were approximately $5,098,000, $4,527,000 and $4,371,000 in 2022, 2021 and 2020, respectively.

We also sponsor two deferred compensation plans for eligible employees. Eligible employees are defined as highly compensated individuals within the definition of the Internal Revenue Code. The plans offer investment options to all eligible participants without regard to salary limits. In addition, one plan enables us to continue employer retirement contributions to highly compensated employees who exceed Internal Revenue Code salary limits for retirement plan contributions. The value of the plans is recorded as an asset and an equal offsetting liability with balances of $4,616,000 and $5,840,000 in 2022 and 2021, respectively.

10. Nuclear insurance:

The Price-Anderson Act limits public liability claims that could arise from a single nuclear incident to $13.7 billion. This amount is covered by private insurance and a mandatory program of deferred premiums that could be assessed against all owners of nuclear power reactors. Such private insurance provided by American Nuclear Insurers (ANI), is carried by Georgia Power for the benefit of all the co-owners of Plants Hatch and Vogtle. Agreements of indemnity have been entered into by and between each of the co-owners and the NRC. In the event of a nuclear incident involving any commercial nuclear facility in the country involving total public liability in excess of $450 million, a licensee of a nuclear power plant could be assessed a deferred premium of up to $138 million per incident for each licensed reactor operated by it, but not more than $20 million per reactor per incident to be paid in a calendar year. On the basis of our ownership interest in five nuclear reactors, we could be assessed a maximum of $206 million per incident, but not more than $31 million in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every 5 years, and exclude any applicable state premium taxes. The next scheduled adjustment is due no later than November 1, 2023.

Georgia Power, on behalf of all the co-owners of Plants Hatch and Vogtle, is a member of Nuclear Electric Insurance, Ltd. (NEIL), a mutual insurer established to provide property damage insurance coverage in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, there is coverage through NEIL for decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that could be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted. In December 2022, we became members of NEIL which will allow us to participate in this coverage in 2023.

Georgia Power, on behalf of all the co-owners has purchased a builders' risk property insurance policy from NEIL for Vogtle Units No. 3 and No. 4. This policy provides $2.75 billion in limits for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to retroactive assessments in proportion to their premiums, if losses each year exceed the accumulated reserve funds available to the insurer. The portion of the current maximum annual assessment for Georgia Power that would be payable by Oglethorpe based on ownership share, is limited to approximately $41 million.

Claims resulting from terrorist acts and cyber events are covered under both the ANI and NEIL policies (subject to normal policy limits). The maximum aggregate that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources. The maximum aggregate that NEIL will pay for all claims resulting from cyber acts and cyber events in any 12-month period is $3.2 billion each, plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are next to be applied toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to Georgia Power, for the benefit of all the co-owners, or to bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability or property, may be subject to applicable state premium taxes. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses. Uninsured losses and other expenses could have a material adverse effect on our financial condition and results of operations.

11. Commitments:

We have entered into long-term commitments to meet fuel, transportation, maintenance and asset retirement requirements.

To supply a portion of the fuel requirements to our co-owned generating units, Georgia Power, on our behalf for coal and Southern Nuclear on our behalf for nuclear fuel, have entered into various long-term commitments for the procurement of coal and nuclear fuel. The contracts in most cases contain provision for price escalations, minimum and maximum purchase levels and other financial commitments. The value of the coal commitments is based on maximum coal prices and minimum volumes as provided in the contracts and does not include taxes, transportation, government impositions or railcar costs.

We have entered into long-term agreements with various counterparties to provide firm natural gas transportation to our natural gas-fired facilities. The value of these agreements is based on fixed rates as provided in the contracts and does not include variable costs.

We have also entered into long-term maintenance agreements for certain of our natural gas-fired facilities. In most cases, these agreements include provisions for price escalation and performance bonuses and, if applicable, are included in the values; timing of expenditures is based on current operational assumptions. Certain agreements contain significant cancellation for convenience penalties and, therefore, amounts in the table below include total estimated expenditures over the life of the agreement. If these agreements were terminated by us in 2023 for convenience, our cancellation obligation would be approximately $96,796,000.

We have asset retirement obligations which are legal obligations to retire long-lived assets. These obligations are primarily for the decommissioning of our nuclear units and coal ash ponds. Expenditures are based on estimates determined through decommissioning studies and include provisions for price escalation and other factors. See Note 1h for information regarding our asset retirement obligations.

We have a small portfolio of leases with the most significant being a finance lease for our 60% undivided interest in Scherer Unit No. 2. In addition, we have other operating leases including railcar leases for the transportation of coal at our coal-fired plants and various other leases of minimal value. For information regarding these leases, see Note 6.

As of December 31, 2022, our estimated commitments are as follows:

(dollars in thousands)	Coal	Nuclear Fuel	Gas Transportation	Maintenance Agreements	Asset Retirement Obligations	Finance and Operating Leases
2023	$ 26,891	$ 78,780	$ 63,850	$ 29,720	$ 16,709	$ 16,273
2024	26,070	39,690	62,818	57,749	52,003	15,799
2025	10,426	32,280	62,775	43,025	46,128	15,590
2026	—	28,980	68,872	15,736	49,445	15,299
2027	—	26,580	67,188	3,237	67,384	15,021
Thereafter	—	67,170	824,627	316,160	3,416,582	11,551

12. Contingencies and Regulatory Matters:

We do not anticipate that the liabilities, if any, for any current proceedings against us will have a material effect on our financial condition or results of operations. However, at this time, the ultimate outcome of any pending or potential litigation cannot be determined.

Environmental Matters

As is typical for electric utilities, we are subject to various federal, state and local environmental laws which represent significant future risks and uncertainties. Air emissions, water discharges and water usage are extensively controlled, closely monitored and periodically reported. Handling and disposal requirements govern the manner of transportation, storage and disposal of various types of waste. We may also become subject to climate change regulations that impose restrictions on emissions of greenhouse gases, including carbon dioxide.

Such requirements may substantially increase the cost of electric service, by requiring modifications in the design or operation of existing facilities or the purchase of emission allowances. Failure to comply with these requirements could result in civil and criminal penalties and could include the complete shutdown of individual generating units not in compliance. Certain of our debt instruments require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current and future environmental laws or regulations. Should we fail to be in compliance with these requirements, it would constitute a default under those debt instruments. We believe that we are in compliance with those environmental regulations currently applicable to our business and operations. Although it is our intent to comply with current and future regulations, we cannot provide assurance that we will always be in compliance.

At this time, the ultimate impact of any potential new and more stringent environmental regulations described above is uncertain and could have an effect on our financial condition, results of operations and cash flows as a result of future additional capital expenditures and increased operations and maintenance costs.

Additionally, litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the United States. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief, personal injury and property damage allegedly caused by coal combustion residue, greenhouse gas and other emissions have become more frequent.

In July 2020, a group of individual plaintiffs filed a complaint, which was amended on December 9, 2022, in the Superior Court of Fulton County, Georgia against Georgia Power alleging that the construction and operation of Plant Scherer, of which we are a co-owner, has impacted groundwater, surface water, and air, resulting in alleged personal injuries and property damage. The plaintiffs seek an unspecified amount of monetary damages including punitive damages, a medical monitoring fund, and injunctive relief. Georgia Power has filed multiple motions to dismiss the complaint, one of which remains pending. On December 29, 2022, the Superior Court of Fulton County granted Georgia Power's motion to transfer the case to the Superior Court of Monroe County. As of the date of this annual report, this case has approximately 48 plaintiffs.

Eight additional complaints, three on October 8, 2021, four on February 7, 2022, and one on January 9, 2023, were filed in the Superior Court of Monroe County, Georgia against Georgia Power alleging that releases from Plant Scherer have impacted groundwater and air, resulting in alleged personal injuries and property damage. The plaintiffs seek an unspecified amount of monetary damages including punitive damages. Georgia Power has removed each of these cases to the U.S. District Court in the Middle District of Georgia. On November 16, 2022, plaintiffs voluntarily dismissed seven of the cases and, on February 21, 2023 the remaining plaintiff voluntarily dismissed the eighth case. Georgia Power has stated that it anticipates seven of these plaintiffs will refile their complaints.

The amount of any possible losses from these matters cannot be estimated at this time.

In May 2022, Florida Power & Light Company and JEA filed a complaint in the U.S. District Court for the Northern District of Georgia against us and the other co-owners of Plant Scherer alleging that their contractual responsibility for a proportionate share of certain common facility costs relating to future environmental projects at Plant Scherer should be decreased following the retirement of Scherer Unit No. 4 at the end of 2021. We and the other co-owners of Plant Scherer filed motions to dismiss Florida Power & Light and JEA's complaint and, on February 9, 2023, the court granted our motions to dismiss with leave to amend. On March 13, 2023, Florida Power & Light and JEA filed an amended complaint. While we do not believe that the co-ownership agreements support the arguments raised by Florida Power & Light Company and JEA, if their arguments were to be successful in this case, we could be responsible for an increased percentage of these costs relating to our interests in Scherer Unit Nos. 1 and 2. The amount of additional costs relating to these future projects, if any, cannot be determined at this time.

13. Plant Wansley:

In July 2022, the Georgia Public Service Commission approved Georgia Power's 2022 integrated resource plan. This plan requested the decertification of coal-fired Plant Wansley, of which we own a 30% interest, by August 31, 2022. In accordance with the approved plan, Georgia Power retired Plant Wansley in August 2022. Beginning in 2021, we accelerated depreciation of the remaining plant in service assets associated with Plant Wansley based upon the August 2022 retirement date and created a regulatory asset to defer a portion of the accelerated depreciation expense. These deferred costs will be recovered through future rates over a period ending no later than December 31, 2040. The Georgia Public Service Commission also approved Georgia Power's modified closure proposal for the ash pond at Plant Wansley. The proposal recommended closure by removing the ash from the coal ash pond for several site-specific reasons, including available capacity at an existing on-site landfill, the retirement of Plant Wansley, beneficial use of the coal ash, and managing construction and operational risks of the previous close in place design. The Georgia Environmental Protection Department must also approve the change in closure plans. At December 31, 2022, we recognized an additional $40,656,000 in liabilities related to the Wansley coal ash pond asset retirement obligation. We expect to periodically receive more refined estimates from Georgia Power regarding closure costs and the timing of expenditures.

14. Plant Acquisition:

On December 20, 2022, we acquired two generating units at the Washington County Power Plant, a four-unit 660 megawatt combustion turbine generation and transmission facility located in Sandersville, Georgia, from Gulf Pacific Power, LLC, an investment fund managed by Harbert Management Corporation. The two acquired units added over 300 megawatts of natural gas-fired capacity to our generation portfolio. As part of the acquisition of the units we assumed an existing power purchase and sale agreement to sell the capacity and associated energy to Georgia Power through May 31, 2024. On June 1, 2024, the output of the acquired units will be available to our subscribing members.

As a result of the power purchase and sale agreement with Georgia Power, our subscribing members are not allowed to take output and we are deferring the current results of operations through the end of the agreement. Residual net results of operations from Washington County, including related interest costs, are being deferred as a regulatory asset. This regulatory asset will be amortized over the then remaining life of the plant, estimated to be 24 years at June 2024.

Some of our members elected to take service (scheduling members) at the end of the power purchase and sale agreement with Georgia Power and some members have elected to defer (deferring members) their share of output until on or before January 2026. Residual net results of operations attributable to the deferring members will also be deferred as a regulatory asset and amortized over the then remaining life of the plant. If a deferring member elects to take service before January 2026, amortization of the regulatory asset will begin upon taking service.

The purchase price was $86,826,000 and the acquisition also included other transaction costs of approximately $1,051,000 (consisting primarily of legal and professional services). We accounted for the acquisition as an asset acquisition. We financed the acquisition on an interim basis through the issuance of commercial paper. We intend to submit a loan application to the Rural Utilities Service for long-term financing of this acquisition. For any amounts not funded through the Rural Utilities Service, we intend to issue first mortgage bonds. We expect that any financing from the Rural Utilities Service or through first mortgage bonds will be secured under our first mortgage indenture.

The following amounts represent the identifiable assets acquired and liabilities assumed in the Washington County acquisition:

Classification	
	(dollars in thousands)
Recognized identifiable assets acquired and liabilities assumed:	
Electric plant in service, net	**$ 80,878**
Inventories, at average cost	**981**
Other current assets	**417**
Power purchase and sale agreement	**4,708**
Other current liabilities	**(158)**
Total identifiable net assets	**$ 86,826**

15. Quarterly financial data (unaudited):

Summarized quarterly financial information for 2022 and 2021 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(dollars in thousands)			
2022				
Operating revenues	**$ 420,442**	**$ 533,128**	**$ 704,265**	**$ 472,302**
Operating margin	**57,845**	**54,269**	**64,553**	**17,384**
Net margin	**21,980**	**18,167**	**32,097**	**(10,540)**
2021				
Operating revenues	$ 376,331	$ 358,127	$ 460,822	$ 409,583
Operating margin	64,573	53,035	46,025	30,748
Net margin	25,958	13,145	8,907	9,771

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members and the Board of Directors of Oglethorpe Power Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Oglethorpe Power Corporation (the Company) as of December 31, 2022 and 2021, the related consolidated statements of revenues and expenses, patronage capital and membership fees and cash flows for each of the three years in the period ended December 31, 2022, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the account or disclosure to which it relates.

Description of the Matter	**Disclosures relating to on-going construction of Vogtle No. 3 and No. 4 units** As more fully described in Note 8b to the consolidated financial statements, the Company, together with Georgia Power Company, the Municipal Electric Authority of Georgia and the City of Dalton, are parties to an ownership participation agreement related to the construction of two additional nuclear power generation units – Plant Vogtle Unit No. 3 and Plant Vogtle Unit No. 4 (the Plants). The Company's current budget for its ownership interest in the Plants is \$8.1 billion, which includes capital costs, allowance for funds used during construction and certain contingencies. This budget reflects the Company's exercise of a tender option contained in the Global Amendments to the Joint Ownership Agreement. Georgia Power does not agree with certain aspects of the tender option. As of December 31, 2022, the total investment in the Plants was approximately \$8.0 billion. Since the inception of construction activities, there have been technical and procedural challenges encountered in the construction and licensing of the

Plants, including changes to the cost estimate and the timing of the completion of the project.

Auditing the Company's disclosure related to the Plants is especially challenging given some of the subjective assumptions made by management which includes estimates of expected remaining construction costs and the timing of completion of these activities. These significant assumptions are forward looking and could be affected by numerous uncertainties, including actions by co-owners of the Plants, challenges with the management of contractors and vendors, subcontractor performance, labor productivity, construction remediation and repair works, completion of the remaining inspection tests, the ability to attract and retain skilled labor, and cost escalations. The final construction timeline and costs may also be impacted by the results of remaining initial testing and start-up activities, including any required engineering changes or remediation related thereto and other unforeseen matters that could arise.

How We Addressed the Matter in Our Audit

To test the adequacy of the Company's disclosures regarding the status, risks and current budget for the nuclear construction project at the Plants, our audit procedures included, among others, evaluating the sensitivity of the Company's project budget to changes in the assumed project completion date based upon the current project status, expected remaining costs and construction costs incurred to date. For example, we tested the underlying incurred cost information by obtaining external confirmation of the construction costs incurred through December 31, 2022 from Georgia Power Company, in its capacity as agent for the joint owners, and compared the confirmed costs to the amounts recorded by the Company in the consolidated financial statements. We also inspected reports regarding the project construction status and other key performance metrics that are used by the Company in assessing the project status and evaluating the adequacy of its project budget. In addition, we discussed with management and the Company's VP of Capital Projects & Technical Services regarding the project status, progress against key milestones, challenges encountered and the related impact on estimated costs to complete the project. We compared this information to the budgeted costs and remaining project contingency funds included in the Company's disclosure. In addition, we read minutes of the Company's construction committee meetings as well as reports of external independent monitors employed by the Georgia Public Service Commission to monitor the state of construction at the Plants and compared this information to the project status.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2010.

Atlanta, Georgia
March 27, 2023

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Responsibility for Financial Statements

Our management has prepared this annual report on Form 10-K and is responsible for the financial statements and related information included herein. These statements were prepared in accordance with generally accepted accounting principles and necessarily include amounts that are based on best estimates and judgments of management. Financial information throughout this annual report on Form 10-K is consistent with the financial statements.

Management believes that our policies and procedures provide reasonable assurance that our operations are conducted with a high standard of business ethics. In management's opinion, our financial statements present fairly, in all material respects, our financial position, results of operations, and cash flows.

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2022 in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information we are required to disclose in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013 framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2022 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our Board of Directors

Structure of our Board of Directors

Our members elect our board of directors. Our board of directors consists of directors and general managers from our members, referred to as "member directors," and up to two outside directors. Our bylaws divide member director positions among the member scheduling groups specifically described in the bylaws, referred to as the "member groups." There are currently five member groups and, except for Group 5, each member group is represented by two member directors. Of each member group's two directors, one must be a general manager of a member in that member group and one must be a director of a member in that member group. Jackson Electric Membership Corporation is the only member in Group 5 and has only one director. The bylaws permit expansion of the number of member groups and changes in the composition of member groups. Formation of new member groups and changes in the composition of member groups are subject to certain required member approvals, and the requirement that the composition of the member groups at Oglethorpe, Georgia Transmission and Georgia System Operations be identical, except in cases where a member is no longer a member of one or more of Oglethorpe, Georgia Transmission or Georgia System Operations. The number of member director positions will change if additional member groups are formed or a member group ceases to exist. The bylaws also provide for three at-large member director positions which may only be filled by a director of one of our members.

In an effort to provide for equitable representation among the member groups across the boards of directors of Oglethorpe, Georgia Transmission and Georgia System Operations, the bylaws provide for certain limitations on the eligibility of directors of members of each member group to fill the three at-large member director positions. No more than one at-large member director position on our board of directors may be filled by a director of a member of any member group, no more than two directors from members of any member group may be serving in at-large member director positions on the boards of directors of Oglethorpe, Georgia Transmission and Georgia System Operations, and at least one at-large member director position on the boards of directors of Oglethorpe, Georgia Transmission or Georgia System Operations must be filled by a director of a member of each member group that has at least two members.

Pursuant to the bylaws, a member may not have both its general manager and one of its directors serve as a director of ours at the same time. Subject to a limited exception for Jackson Electric Membership Corporation, which is the sole member of one of the member groups, the bylaws prohibit any person from simultaneously serving as a director of Oglethorpe and either Georgia Transmission or Georgia System Operations.

Our bylaws require outside directors to have experience related to our business, including, without limitation, operations, marketing, finance or legal matters. No outside director may be one of our current or former officers, a current employee of ours or a former employee of ours receiving compensation for prior services. Outside directors cannot also be a director, officer or employee of Georgia Transmission, Georgia System Operations or any member. Additionally, no person who receives payment from us in any capacity other than as an outside director, including direct or indirect payments for goods and services, may serve as outside director.

The members of our board of directors serve staggered three-year terms.

Our board of directors currently has two vacancies. One of the vacancies is for an at-large member position and the other is for an outside director position. Our members did not fill either of the two vacancies in 2022, and we do not anticipate that our members will elect directors to fill those vacancies during 2023.

Election of our Board of Directors

For a cooperative organization to maintain its status under federal tax law, it must abide by the cooperative principle of democratic control. The nomination and election of the members of our board of directors and the representation of our members by the elected directors is consistent with this principle.

Candidates for our board of directors must be nominated by the nominating committee. The nominating committee is comprised of one representative from each of our members. A majority vote of the nominating committee is required to nominate each candidate for the board of directors. Each member representative's nomination vote is weighted based on the number of retail customers served by the member. After the nominating committee nominates a candidate for a director position, the candidate must be elected by a majority vote of all of our member representatives, voting on an unweighted, one-member, one-vote basis. If the nominated candidate fails to receive a majority of the vote, the nominating committee must nominate another candidate and the member representatives will vote on the new candidate. Should that candidate also fail to receive a majority vote, this nomination and election process would be repeated until a nominated candidate is elected by a majority of the members.

Potential candidates for our board of directors must meet the requirements set forth in our bylaws, as discussed under *"–Structure of our Board of Directors."* Management does not have a direct role in the nomination or election of the members of our board of directors.

Neither we, the nominating committee, nor any of our members, to our knowledge, have a policy with regard to the consideration of diversity in identifying potential candidates for our board of directors.

Board of Directors Leadership Structure

Our principal executive officer and chairman of the board positions are separate and are held by different persons. The chairman of the board and any vice-chairman of the board are elected annually by a majority vote of the members of our board of directors. Our president and chief executive officer is appointed by our board of directors. None of our executive officers or other employees are members of our board of directors.

As a cooperative, our members are our owners. Our members believe that the most effective structure to efficiently provide for their current and future needs is to take a prominent role in the direction of our business. Member control over the board of directors, and the board of directors' independence from management is beneficial and provides for member input. Direct accountability to and separation from the board of directors helps ensure that management acts in the best interests of our members.

Executive Officer and Director Biographies

Our executive officers and directors are as follows:

Name	Age	Position
Executive Officers:		
Michael L. Smith	63	President and Chief Executive Officer
Elizabeth B. Higgins	54	Executive Vice President and Chief Financial Officer
David W. Sorrick	59	Executive Vice President and Chief Operating Officer
William F. Ussery	58	Executive Vice President, Member Relations
Annalisa M. Bloodworth	44	Senior Vice President and General Counsel
Lori K. Holt	61	Senior Vice President, Fuels & Co-owned Assets
Jeffrey R. Swartz	60	Senior Vice President, Plant Operations
Heather Teilhet	47	Senior Vice President, External Affairs
Jami G. Reusch	60	Vice President, Human Resources
Directors:		
Marshall S. Millwood	73	Chairman and Member Group Director (Group 3)
James I. White	77	Vice-Chairman and Member Group Director (Group 1)
Jimmy G. Bailey	74	At-Large Director
Horace H. Weathersby III	63	At-Large Director
George L. Weaver	75	Member Group Director (Group 1)
Danny L. Nichols	58	Member Group Director (Group 2)
Sammy G. Simonton	81	Member Group Director (Group 2)
Randy Crenshaw	70	Member Group Director (Group 3)
Fred A. McWhorter	76	Member Group Director (Group 4)
Jeffrey W. Murphy	59	Member Group Director (Group 4)
Ernest A. "Chip" Jakins III	53	Member Group Director (Group 5)
Wm. Ronald Duffey	81	Outside Director

Executive Officers

Overview

We are managed and operated under the direction of a president and chief executive officer who is appointed by our board of directors. Our president and chief executive officer selects the remainder of the executive officers. Certain of our executive officers have entered into an employment contract with us that provides for minimum annual base salary and performance pay. See "EXECUTIVE COMPENSATION – Compensation Discussion and Analysis – Employment Agreements" for further discussion of these agreements.

Executive Officer Biographies

Michael L. Smith is our President and Chief Executive Officer and has served in that capacity since November 2013. Prior to joining Oglethorpe, Mr. Smith served as Georgia Transmission's President and Chief Executive Officer from 2005 to 2013 after he joined Georgia Transmission as its Senior Vice President and Chief Financial Officer in 2003. From 2002 to 2003, Mr. Smith co-founded and served as the Executive Director of the Committee of Chief Risk Officers. From 1997 to 2002, Mr. Smith held multiple positions at Mirant Corporation, most recently as Vice President and Global Risk Officer. From 1994 to 1997, he was Manager of Planning and Evaluation for Vastar Resources and prior to that he worked at ARCO in various positions from 1983 to 1994. Mr. Smith has a Bachelor's degree in Business Law and a Masters of Business Administration in Finance from Louisiana State University. Mr. Smith is on the board of directors for the Georgia Chamber of Commerce, the Georgia Energy and Industrial Construction Consortium and for ACES Power Marketing.

Elizabeth B. Higgins is our Executive Vice President and Chief Financial Officer and has served in that office since July 2004. In October 2008, Ms. Higgins' title changed from Chief Financial Officer to her current title. Ms. Higgins served as Senior Vice President, Finance & Planning of Oglethorpe from July 2003 to July 2004. Ms. Higgins served as Vice President of Oglethorpe with various responsibilities including strategic planning, rates, analysis and member relations from September

2000 to July 2003. Ms. Higgins served as the Vice President and Assistant to the Chief Executive Officer of Oglethorpe from October 1999 to September 2000 and served in other capacities for Oglethorpe from April 1997 to September 1999. Prior to that, Ms. Higgins served as Project Manager at Southern Engineering from October 1995 to April 1997, as Senior Consultant at Deloitte & Touche, LLP from April 1995 to October 1995, and as Senior Consultant at Energy Management Associates from June 1991 to April 1995. Ms. Higgins has a Bachelor of Industrial Engineering degree from the Georgia Institute of Technology and a Master of Business Administration degree from Georgia State University. Ms. Higgins serves on the advisory board of FM Global and is a member of the Rotary Club of Atlanta. She also serves as a mentor with Pathbuilders, a development program for high potential women.

David W. Sorrick is our Executive Vice President and Chief Operating Officer and has served in that capacity since February 2022. Mr. Sorrick has more than 30 years of energy generation experience. From March to December 2021, he was the Senior Vice President, Power Operations at New Fortress Energy and from March 2019 to March 2021 he was Director, Asset Management and Optimization for the Electric Power Research Institute. From January 2015 to October 2018, Mr. Sorrick was with the Tennessee Valley Authority and for the last two years acted as Senior Vice President, Power Operations with responsibility for its fleet of natural gas, hydropower and coal-fired generation resources. Prior to that, he held key positions with Duke Energy, Progress Energy, GE Power Systems and Florida Power Corp. Mr. Sorrick is a licensed professional engineer who holds a Masters of Business Administration degree from the University of South Florida and a Bachelor of Science degree in Electrical Engineering from the University of Tennessee at Chattanooga.

William F. Ussery is our Executive Vice President, Member Relations and has served in that office since October 2005. In October 2008, Mr. Ussery's title changed from Senior Vice President, Member and External Relations to Executive Vice President, Member and External Relations. In January 2020, Mr. Ussery's title changed to Executive Vice President, Member Relations. Mr. Ussery previously served as Vice President and Assistant Chief Operating Officer of Oglethorpe from November 2003 to October 2005. Prior to joining Oglethorpe in 2001, Mr. Ussery held several key positions, including Chief Operating Officer, Vice President of Engineering and System Engineer at Sawnee Electric Membership Corporation. Mr. Ussery holds a Bachelor of Science degree in Electrical Engineering from Auburn University and an associate degree in Science from Middle Georgia College. Since March 2007, Mr. Ussery has served as a board member of the Council on Alcohol and Drugs, Inc. and previously served as its Chairman.

Annalisa M. Bloodworth is our Senior Vice President and General Counsel and has served in that capacity since January 2017. Ms. Bloodworth joined Oglethorpe in 2010 and served in various roles prior to taking her current position, most recently as Deputy General Counsel. Prior to joining Oglethorpe, Ms. Bloodworth was in private practice at Eversheds Sutherland (US) LLP. In addition to energy, her legal experience includes significant work in commercial development, real estate, regulatory compliance, and construction contracting. Ms. Bloodworth is a graduate of Trinity University where she earned a Bachelor of Arts in Economics and Emory University School of Law where she earned her Juris Doctor degree. Ms. Bloodworth is a member of the International Women's Forum, Leadership Georgia, and Leadership Atlanta. She serves as Treasurer for the board of directors of Murphy-Harpst Children's Home, and is a Past-President of the Emory University School of Law Alumni Board.

Lori K. Holt is our Senior Vice President, Fuels & Co-owned Assets and has served in that capacity since January 2017. Ms. Holt joined us in 2009 as Vice President of Fuels and Energy. From 2002 to 2009, Ms. Holt was Managing Director of Business Development for ACES. Prior to joining ACES, she was involved with power plant development for Panda Power Funds. Ms. Holt graduated from the University of Louisville with a Bachelor of Science in Business Administration degree.

Jeffrey R. Swartz is our Senior Vice President, Plant Operations and has served in that capacity since September 2022. Prior to joining us, Mr. Swartz was Vice President for Power Operations for New Fortress Energy from 2021 to 2022. Prior to that, he was Vice President of Plant Generation Operations for Duke Energy Florida, LLC from 2012 to 2021 and began working for other subsidiaries of Duke Energy Corporation in 2001. Mr. Swartz graduated from the United States Naval Academy with a Bachelor of Science in Mechanical Engineering degree and is a veteran of the U.S. Navy with engineering experience in nuclear power.

Heather H. Teilhet is our Senior Vice President, External Affairs and has served in that capacity since January 2020. Ms. Teilhet joined us in January 2017 as Vice President of Governmental Affairs. Prior to joining us, Ms. Teilhet served as Vice President of Government Relations for Georgia Electric Membership Corporation from 2010 to 2016, where she represented Georgia's 41 electric cooperatives before the Georgia General Assembly, the U.S. Congress and certain regulatory agencies. Prior to joining Georgia EMC, she served as a senior staff member for Georgia Governor Sonny Perdue and as a staff member for Georgia Governor Roy Barnes. Ms. Teilhet graduated from the University of Georgia and holds a Masters in Public Administration from Georgia State University.

Jami G. Reusch is our Vice President, Human Resources and has served in that office since July 2004. Ms. Reusch served as Oglethorpe's Director of Human Resources and held several other management and staff positions in Human Resources prior to July 2004. Prior to joining Oglethorpe in 1994, Ms. Reusch was a senior officer in the banking industry in Georgia, where she held various leadership roles. Ms. Reusch has a Bachelor of Education degree and a Master of Human Resource Development degree from Georgia State University. She also holds several Senior Professional certificates in Human Resources Management.

Board of Directors

Director Qualifications

As required by our bylaws, all of the members of our board of directors, except for the outside director, are either directors or general managers of one of our members. This prerequisite helps to insure that the members of our board of directors have business experience related to electric membership corporations as well as an interest in the successful operation of our business. The members of our board of directors are elected solely by the vote of our members; we have no direct role in the nomination of the candidates or the election of members to our board of directors. Therefore, the following director biographies do not include a discussion of the specific experience, qualifications, attributes or skills that led our members to the conclusion that a person should serve as a director on our board of directors. For further discussion of our nomination and election process, see "– Our Board of Directors – *Election of our Board of Directors.*"

Director Biographies

Jimmy G. Bailey is an at-large director. Mr. Bailey has served on our board of directors since September 2015 and his present term will expire in March 2025. Mr. Bailey is a member of the compensation committee and the construction project committee. Mr. Bailey is a director of the Diverse Power Incorporated, an EMC, and served as the Chairman of Diverse Power board from 2018 to 2020. Mr. Bailey owned and operated a construction contracting business from 1970 to 2018. He also served as Chairman of Kudzu Networks Inc., a subsidiary of Diverse Power, and was President of the Georgia Directors Association in 2017 and 2018.

Randy Crenshaw is a member group director (group 3). Mr. Crenshaw has served on our board of directors since March 2016, and his present term will expire in March 2025. He is a member of the audit committee. Mr. Crenshaw is President and Chief Executive Officer of Irwin Electric Membership Corporation and Middle Georgia Electric Membership Corporation. Mr. Crenshaw also serves on the board of directors for Georgia Electric Membership Corporation, Green Power EMC and Smarr EMC and is chairman of the board of directors for GRESCO Utility Supply, Inc. He is a former member of the Georgia System Operations board of directors and former chairman of the Georgia Cooperative Council board of directors. He is also President of the Irwin/Ocilla Chamber of Commerce.

Wm. Ronald Duffey is an outside director. Mr. Duffey has served on our board of directors since March 1997, and his present term will expire in March 2024. He is the chairman of the audit committee and served as special liaison between senior management and the board during the search for a successor president and chief executive officer from June to November 2013. Mr. Duffey is the retired Chairman of the Board of Directors of Peachtree National Bank in Peachtree City, Georgia, a wholly owned subsidiary of Synovus Financial Corp. Prior to his employment in 1985 with Peachtree National Bank, Mr. Duffey served as Executive Vice President and a member of the board of directors for First National Bank in Newnan, Georgia. He holds a Bachelor of Business Administration degree from Georgia State College with a concentration in finance and has completed banking courses at the School of Banking of the South, Louisiana State University, the American Bankers Association School of Bank Investments, and The Stonier Graduate School of Banking, Rutgers University. Mr. Duffey is the immediate past Chair of the board of directors of Piedmont Healthcare, where he also served on the Executive Committee, Executive Performance and Compensation Committee and Governance, Nominating Committee and was past Chair of the Audit Committee. Mr. Duffey is also a former member of the Georgia Chamber of Commerce board of directors.

Ernest A. "Chip" Jakins III is a member group director (group 5). Mr. Jakins has served on our board of directors since 2014, and his present term will expire in March 2026. Mr. Jakins is chairman of the compensation committee and also serves on the construction project committee. Mr. Jakins is currently the President and Chief Executive Officer of Jackson Electric Membership Corporation and was previously President and Chief Executive Officer of Carroll Electric Membership Corporation. He also serves as a director for Georgia System Operations, where he is a member of the compensation committee, for Georgia Electric Membership Corporation where he is a member of the Economic Development Committee, and for Green Power EMC. He is also a member of the Georgia Chamber of Commerce.

Fred A. McWhorter is a member group director (group 4). Mr. McWhorter has served on our board of directors since September 2012, and his present term will expire in March 2025. He is a member of the compensation committee and the construction project committee. Mr. McWhorter serves as Chairman of the Rayle Electric Membership Corporation board of directors. Mr. McWhorter also serves on the board of directors for Georgia Electric Cooperative. He is the owner of F.A. McWhorter Poultry Farms.

Marshall S. Millwood is the Chairman of the Board and a member group director (group 3). Mr. Millwood has served on our board of directors since March 2003, and his present term will expire in March 2026. He has been the owner and operator of Marjomil Inc., a poultry and cattle farm in Forsyth County, Georgia, since 1998. He is a director of Sawnee Electric Membership Corporation.

Jeffrey W. Murphy is a member group director (group 4). Mr. Murphy has served on our board of directors since March 2004, and his present term will expire in March 2024. He is a member of the audit committee. Mr. Murphy has been the President and Chief Executive Officer of Hart Electric Membership Corporation since May 2002. He is also the Secretary of Georgia Energy Cooperative.

Danny L. Nichols is a member group director (group 2). Mr. Nichols has served on our board of directors since March 2011, and his present term will expire in March 2026. Mr. Nichols is the chairman of the construction project committee and also serves on the compensation committee. Mr. Nichols is the General Manager of Colquitt Electric Membership Corporation.

Sammy G. Simonton is a member group director (group 2). Mr. Simonton has served on our board of directors since October 2012, and his present term will expire in March 2024. He is a member of the audit committee. Mr. Simonton is a director of Walton Electric Membership Corporation. Mr. Simonton is currently the owner of Simonton Farms and has previous business affiliations with Meridian Homes, Moreland Altobelli Associates, Inc. and the Georgia Department of Transportation.

Horace H. Weathersby III is an at-large director. Mr. Weathersby has served on our board of directors since 2022, and his present term will expire in March 2026. He is a member of the compensation committee and the construction committee. Mr. Weathersby is a director of Planters Electric Membership Corporation where he has served since 2006 and currently serves as Chairman. Mr. Weathersby is the owner of Millen Peanut Company and Horace Weathersby Farms. Mr. Weathersby is also a director of Georgia Electric Membership Corporation, Jenkins County Commission and South Jenkins Volunteer Fire Department.

George L. Weaver is a member group director (group 1). Mr. Weaver has served on our board of directors since March 2010, and his present term will expire in March 2025. He is a member of the audit committee. Mr. Weaver has been employed by Central Georgia Electric Membership Corporation since 1970 and is currently serving as President and Chief Executive Officer. Mr. Weaver is currently a director of Meridian Cooperative and is a former director of Federated Rural Electric Insurance Corporation.

James I. White is Vice-Chairman of the Board and a member group director (group 1). Mr. White has served on our board of directors since March 2012, and his present term will expire in March 2026. He is a member of the audit committee. Mr. White has served as a director of Snapping Shoals Electric Membership Corporation since 1995. Mr. White is the owner and president of Realty South Inc. and the owner of T.K. White Real Estate Co. and is a member of the Metro South Association of Realtors and Georgia Association of Realtors. Mr. White was involved with the Henry County Development Authority for over 20 years. He was previously vice president at the First National Bank in Crestview, Florida.

Committees of the Board of Directors

Our board of directors has established an audit committee, a compensation committee and a construction project committee. The audit committee, the compensation committee and the construction project committee each operate pursuant to a committee charter and/or policy. We do not have a nominating and corporate governance committee; directors are nominated by representatives from each member whose weighted nomination is based on the number of retail customers served by each member, and after nomination, elected by a majority vote of the members, voting on a one-member, one-vote basis.

Audit Committee. The audit committee is responsible for assisting the board of directors in its oversight of various aspects of our business, including all material aspects of our financial reporting functions as well as risk assessment and management. Its responsibilities related to financial reporting include selecting our independent accountants, reviewing the plans, scope and results of the audit engagement with our independent accountants, reviewing the independence of our independent accountants and reviewing the adequacy of our internal accounting controls. The audit committee also reviews our policy standards and guidelines for risk assessment and risk management as discussed further under "– Board of Directors' Role in Risk Oversight." As of the date of this annual report, the members of the audit committee are Ronald Duffey, Randy Crenshaw, Jeffrey Murphy, Sam Simonton, George Weaver and James White. Mr. Duffey is the chairman of the audit committee. The board of directors has determined that Mr. Duffey qualifies as an independent audit committee financial expert.

Compensation Committee. The compensation committee is responsible for monitoring adherence with our compensation programs and recommending changes to our compensation programs as needed. As of the date of this annual report, the members of the compensation committee are Chip Jakins, Jimmy Bailey, Fred McWhorter, Danny Nichols and Horace Weathersby. Mr. Jakins is the chairman of the compensation committee.

Construction Project Committee. The construction project committee is responsible for reviewing and making recommendations to our board of directors with regards to major actions or commitments relating to new power plant construction projects and certain existing plant modification projects. Its responsibilities include reviewing and recommending to our board of directors final plant sites, project budgets (including certain modifications to project budgets) and project construction plans, and a quarterly reviewing of and reporting on the status of projects. As of the date of this annual report, the members of the construction project committee are Danny Nichols, Jimmy Bailey, Chip Jakins, Fred McWhorter and Horace Weathersby. Mr. Nichols is the chairman of the construction project committee.

Board of Directors' Role in Risk Oversight

Our board of directors and the audit committee both actively oversee our exposure to risks in our business. Our board of directors has adopted corporate policies regarding management of risks related to financial management, capital investment and the use of derivatives. One of the primary risk oversight activities of the board of directors is to hold an annual strategic planning session to review potentially material threats and opportunities to our business. To facilitate this review, management develops a comprehensive strategic issues matrix. The strategic issues matrix identifies, describes, assesses and classifies the potential impact or magnitude, and outlines corporate strategies for addressing potentially material threats and opportunities to our business. During this session, our board of directors reviews these analyses and affirms or assists management with developing strategies to address these strategic risks and opportunities. Additionally, management also develops and typically shares a corporate risk map with our audit committee. The corporate risk map depicts the probability of occurrence and the potential severity for each significant corporate risk.

At each regular meeting of the board of directors, management provides the board with reports on significant changes related to the top strategic risks and opportunities facing us and a revised version of the strategic issues matrix that highlights any revisions to the matrix. The audit committee chairman also provides the board of directors with updates on overall corporate risk exposure. Furthermore, the board of directors receives risk analysis reports that identify key risks that could create variances from our approved annual budget and long-range forecasts and discuss the potential likelihood and magnitude of changes to member rates related to these risks based on scenario modeling.

Our board of directors has delegated direct oversight of corporate risk management and compliance to the audit committee. Pursuant to its charter, the audit committee reviews our business risk management process, including the adequacy of our overall control environment, in selected areas that represent significant financial and business risks. The audit committee receives regular reports on the activities of the risk management and compliance committee, which are described below, as well as quarter-end reports, which include changes to derivative hedge positions and overall corporate risk exposure. Additionally, the audit committee provides oversight over corporate ethics and compliance matters and receives regular reports on compliance, which include, but are not limited to, the review of (i) significant compliance issues, (ii) significant audits/examinations by governmental or other regulatory agencies, and (iii) significant regulatory proceedings. The risk management and compliance committee, comprised of our chief executive officer, chief operating officer, chief financial officer, and the executive vice president of member and external relations, provides general oversight over all of our risk management and compliance activities, including but not limited to commodity trading, fuels management, insurance procurement, debt management, investment portfolio management, environmental and electric reliability compliance and cyber-security. The risk management and compliance committee has implemented comprehensive policies and procedures, consistent with current board policies, which govern our activities pertaining to market, compliance/regulatory and other risks. For further discussion about our risk management and compliance committee and its activities, see "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK."

Code of Ethics and Code of Conduct

We have adopted a Code of Conduct that applies to all our employees, including our principal executive, financial and accounting officers. Our Code of Conduct is available at our website, www.opc.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Executive Summary

The philosophy and objective of our compensation and benefits program is to establish and maintain competitive total compensation programs that will attract, motivate and retain the qualified and skilled workforce necessary for our continued success. The compensation committee of the board of directors has the primary responsibility for establishing, implementing and monitoring adherence with our compensation programs. To help align executive officers' interests with those of our members, we have designed a significant portion of our cash compensation program as a pay for performance based system that rewards executive officers based on our success in achieving the corporate goals discussed below. To remain competitive, we review our total compensation program against generally available market data to gain a general understanding of current compensation practices.

Components of Total Compensation

The compensation committee determined that compensation packages for the fiscal year ended December 31, 2022 for our executive officers should be comprised of the following three primary components:

- Annual base salary,
- Performance pay, which consists of a cash award based on the achievement of corporate goals, and
- Benefits, which consist primarily of health, welfare and retirement benefits.

Certain of our executive officers have an employment agreement that provides for minimum annual base salary and performance pay. See "– *Employment Agreements*."

Since we are an electric cooperative, we do not have any stock and as a result do not have equity-based compensation programs.

Base Salary. Base salary is the primary component of our compensation program and it is set at a level to attract and retain executives who can lead us in meeting our corporate goals. Base salary levels are set based on several factors, including but not limited to the position's duties and responsibilities, the individual's value and contributions to the company, work experience and length of service.

Performance Pay. Performance pay is designed to reward executive officers based on the achievement of certain strategic corporate goals. The corporate goals selected are designed to align the interests of our executive officers and employees with the interests of our members. The compensation committee believes it is appropriate to consider only corporate goal achievement when determining executive officers' performance pay because our corporate philosophy focuses on teamwork, and we believe that better results evolve from mutual work towards common goals. Furthermore, the compensation committee believes that our achievement of these corporate goals will correspond to high company performance, and our executive officers are responsible for directing the work and making the strategic decisions necessary to successfully meet these goals. For 2022, each executive officer was eligible to receive up to 20% of his or her base salary as a performance bonus based on the achievement of corporate goals. For 2023, we increased the performance bonus amounts and each executive officer will be eligible to receive up to 30% or 35% of his or her base salary based on the achievement of corporate goals and his or her position.

Importantly, our executive officers cannot help us meet our goals and improve performance without the work of others. For this reason, the performance goals set at the corporate level are the same for both executive officers and non-executive employees.

Benefits. The benefits program is designed to allow executive officers to choose the benefit options that best meet their needs. Our president and chief executive officer recommends changes to the benefits program or level of benefits that all executive officers, including our president and chief executive officer, receive to the compensation committee. The compensation committee then reviews and recommends changes to the board of directors for its approval. To meet the health and welfare needs of our executive officers at a reasonable cost, we pay for 80-85% of an executive officer's health and welfare benefits. Our president and chief executive officer decides our exact cost sharing percentage. We also provide each executive officer with life insurance coverage of two times the officer's base salary, up to $800,000, as well as disability insurance at a level equal to 60% of the officer's base salary. The health, life and disability insurance coverage we provide to our executive officers is consistent with the coverage we provide to our employees generally.

We also provide retirement benefits that allow executive officers the opportunity to develop an investment strategy that best meets their retirement needs. We will contribute up to $0.75 of every dollar an executive officer contributes to his or her retirement plan, up to 6% of an executive officer's pay per period. In 2022, we contributed an additional amount equal to 11% of an executive officer's pay per period. See "– Nonqualified Deferred Compensation" below for additional information regarding our contributions to our executive officers' retirement plans.

Perquisites. We provide our executive officers with perquisites that we and the compensation committee believe are reasonable and consistent with our overall compensation program. The most significant perquisite provided to our executive officers is a monthly car allowance, the amount of which is based upon the executive officer's position. Our president and chief executive officer approves the executive officers eligible for car allowances and reports this information to the compensation committee. The car allowance for our president and chief executive officer is included in his employment agreement. The compensation committee periodically reviews the levels of perquisites provided to executive officers.

Bonuses. Our practice has been to, on infrequent occasions, award cash bonuses to senior management related to exemplary performance. Our compensation committee may determine bonus criteria and may recommend discretionary bonuses for our president and chief executive officer to our board of directors for approval. Our president and chief executive officer may determine bonus criteria and issue discretionary bonuses to other members of senior management.

Establishing Compensation Levels

Role of the Compensation Committee. The compensation committee annually reviews each of the components of our compensation program for our officers, directors and employees and recommends any changes to our board of directors for approval. To aid in this review, the compensation committee receives a comprehensive report on an annual basis regarding all facets of our compensation program. In order to have a compensation program that is internally consistent and equitable, the compensation committee considers several subjective and objective factors when determining the compensation program. The compensation committee also approves our performance pay program including, the corporate goals related to such program.

The compensation committee currently reviews and recommends to the board of directors for approval the compensation, including any bonus, for our president and chief executive officer. Some of the factors reviewed include the position's duties and responsibilities, the individual's job performance, experience, longevity of service and overall value provided for our members. Each year, the compensation committee reviews the employment agreement of our president and chief executive officer and makes a recommendation to our board of directors whether it should be extended.

The compensation committee operates pursuant to a statement of functions that sets forth the committee's objectives and responsibilities. The compensation committee's objective is to review and recommend to the board of directors for approval any changes to various compensation related matters, as well as any significant changes in benefits cost or level of benefits, for the members of the board of directors, the executive officers, and other employees. The compensation committee annually reviews its statement of functions and makes any necessary revisions to ensure its responsibilities are accurately stated.

Role of Management. Our president and chief executive officer is the key member of management involved in our compensation process. He annually reviews the compensation of our other executive officers and in certain circumstances provides an adjustment to the executive officers' base salaries. Some of the factors the president and chief executive officer considers include the person's relative responsibilities and duties, experience, job performance, longevity of service and overall value provided for our members. Our president and chief executive officer also reviews any employment agreements with our executive officers on an annual basis and makes an affirmative decision whether each should be extended. Our president and chief executive officer reports the executive officers' salaries and determination whether to extend the employment agreements, if applicable, to the compensation committee and board of directors annually.

Our president and chief executive officer, together with the other executive officers, identifies corporate performance objectives that are used to determine performance pay amounts. He and our vice president, human resources present these goals to the compensation committee. The compensation committee then reviews and approves the goals and presents them to the board of directors for final approval.

Role of the Board of Directors. Our board of directors must approve changes recommended by the compensation committee before the changes may take effect. These approvals include the compensation of our president and chief executive officer, the extension of the president and chief executive officer's employment agreement, and the components of our compensation program each year.

Role of Generally Available Market Data. To confirm that our compensation levels remain competitive, we review standardized surveys to compare our total compensation program against other companies in the utility industry of a similar size. We utilize these surveys to gain a general understanding of current compensation practices and better understand and compare the components of our compensation program. The surveys we review are generally available and executive compensation levels at other companies do not drive our compensation decisions. For our employees overall and for our executive officers, we review market compensation levels as a reference point in our overall compensation review process.

In order to supplement our internal review of generally available market data, we periodically hire a compensation consultant to provide us with supplemental market information to help us evaluate our compensation practices. In 2022, we engaged an independent consultant to provide supplemental market data regarding the relative competitiveness of our compensation.

Corporate Goals for Performance Pay

We choose to tie performance compensation to selected corporate goals that most appropriately measure our achievement of our strategic objectives. For 2022, our performance measures were divided into the following categories: (i) safety, (ii) operations, (iii) construction and project management, (iv) corporate compliance, (v) financial and (vi) quality. Targeted performance measures in these categories are designed to help us accomplish our corporate goals which will benefit our members, employees and promote responsible environmental stewardship.

For an executive officer to earn his or her maximum performance pay, 100% of the performance measures must be achieved. The performance measures are weighted to align with our current strategic focus. Goals are reviewed annually and may be adjusted in order to reflect any changes in our strategic focus. We also review and refine these goals annually and make adjustments as necessary to ensure that we are consistently stretching our expectations and performance. Although some performance measures may stay the same, the applicable threshold may become more difficult. The following provides an overview of the purposes of each category of our corporate goals:

Safety. Our safety goals provide employees a financial incentive to focus on a safe workplace environment, which increases employee morale and minimizes lost work time. Our safety performance goals focused on the number of lost time incidents, safety training and meetings, enhancing our safety program and procedures and reducing workplace hazards for both our employees and contractors.

Operations. The operations goals measure how well each of our operating plants responds to system requirements. In order to optimize generation for system load requirements, we generally dispatch the most efficient and economical generation resources first. If the preferred generation resource is not available when called upon, we must resort to a more expensive alternative. Most of the performance measures in this category, including successful starts and peak season availability, are measured against industry averages and the applicable thresholds are set above average. To meet these standards, we or the operator of certain co-owned facilities must operate and maintain these facilities in a manner that minimizes long-term maintenance and replacement energy costs. Our achieving operational excellence at the corporate level results in the most reliable, efficient and lowest cost power supply for our members.

Construction and Project Management. Our construction and project management goals measure our involvement and management regarding construction at our owned and co-owned generating facilities. Our most significant project is the construction of Vogtle Units No. 3 and No. 4. One of the goals measures how well we are managing the project in our role as a Co-owner. Performance is based on our participation on the Project Management Board, the degree and effectiveness of oversight involvement, understanding of the project status and project issues, and timeliness and usefulness of project communications to our members and our board of directors. Our president and chief executive officer will assign a score based on his assessment of the overall effectiveness of our management of the project and submit the score to the construction committee of our board of directors for approval. Other components measure construction progress at the Vogtle project as well as construction projects that we directly oversee, and we measure performance based on successful project completion in a timely manner and within project budget.

Corporate Compliance. Our corporate compliance goals are divided into two categories – environmental and electric reliability standards. The environmental goals promote our commitment to responsible environmental stewardship while providing reliable and affordable energy. We measure our performance by the number of environmental incidents, such as spills, which not only increase costs for our members but may cause environmental damage. Electric reliability standards compliance is measured by reviewing our performance as determined by standards set by the electric reliability organizations related to protection of our critical and non-critical infrastructure.

Financial. Our financial goals provide direct benefits to our members by lowering power costs. One goal is tied to specific financial performance while others focus on emphasizing importance of appropriate and effective internal controls. For example, the cost savings goal is designed to encourage staff to identify and implement strategies that result in cost savings or cost reductions in either the current year or on a long-term basis. Any cost savings included in this goal must be over and above what would generally be expected. For 2022, we may earn up to an additional 5% of performance pay by identifying cost savings or reduction strategies above the initial $50 million goal. Two other financial goals focus on our internal controls over financial reporting.

Quality. Quality is a subjective goal that is intended to measure the satisfaction of our members with our efforts, initiatives, responsiveness and other intangibles that are not readily quantified. Performance on this goal is based on semi-annual surveys submitted by the members of the board of directors who, except for our outside director, are general managers or directors of our members. The results of the surveys are averaged to determine the total quality result. In order to achieve the maximum award, we must receive a 100% rating from every member of the board of directors on both surveys, an extremely high standard that has yet to be achieved.

Calculation of Performance Pay Earned

Performance pay earned by our executive officers is based on our success in achieving each of our corporate goals. Annually, our board of directors approves a weighted system for determining performance pay whereby we assign a percentage to each of the goals, as noted below. Based on the achievement of each performance metric, a percentage of the weighted goal is available as performance pay to our executive officers. Each performance metric has a minimum threshold level that must be achieved before any performance pay is earned. If the actual performance for that metric meets the applicable threshold, then a pre-determined percentage of the percentage pay for that metric will be awarded. The percentage awarded will increase up to a maximum of 100% of the weighted goal if the maximum performance level of the performance metric is achieved. Threshold and maximum levels are reviewed annually and generally reset as necessary to demand ever improving corporate performance. Meeting the applicable thresholds is not guaranteed and requires diligence and hard work. Exceptional performance is required to reach the maximum goals.

For 2022, we multiplied 20% of each executive officers' base salary by the corporate goal achievement percentage to determine his or her performance bonus.

Assessment of Performance of 2022 Corporate Goals

The specific corporate performance measures, thresholds, maximums and results for our executive officers' 2022 performance pay were the following:

Performance Category/ Description	Performance Measure	Threshold	Maximum	2022 Result	Weight	Weighted Goal Achieved
Safety						
Incident Rate	Lost Work Time Incidents	1 (if not OSHA)	0	4	3.0 %	0.00 %
Safety Program[1]	Safety Training and Meetings	100.0 %	100.0 %	100.0 %	1.0 %	1.00 %
	Safety Observation Program	198/110	330/220	370/285	2.5 %	2.50 %
	Hazard Reduction Program	75.0 %	100.0 %	100.0 %	0.5 %	0.50 %
Operations[2]						
Oglethorpe Managed	Successful Starts	96.4 %	100.0 %	99.7 %	4.0 %	2.90 %
Fleet	Successful Dispatch	90.0 %	97.5 %	97.7 %	2.0 %	1.56 %
	Peak Season Availability	71.2 %	99.9 %	88.2 %	21.0 %	18.53 %
Co-Owned Fleet	Coal Fleet Peak Season Equivalent Forced Outage Rate	8.2 %	5.4 %	2.3 %	0.65 %	0.65 %
	Coal Fleet Annual Equivalent Unplanned Unavailability Factor	8.8 %	5.8 %	9.0 %	0.35 %	0.08 %
	Nuclear Fleet Capability Factor	92.9 %	94.9 %	94.3 %	2.0 %	1.37 %
Construction and Project Management						
Vogtle Units No. 3 and No. 4	Oglethorpe Performance	0.0 %	100.0 %	100.0 %	7.0 %	7.00 %
	Status of Project	Meet applicable deadlines		0.0 %	3.0 %	0.00 %
Oglethorpe Managed Projects	Status of Projects	Meet applicable deadlines & budgets		100.0 %	6.0 %	6.00 %
Corporate Compliance						
Environmental	Final Notices of Violation and Letters of Non-Compliance	1 (if fine is ≤ $5,000) or 2	0	0	4.0 %	4.00 %
	Reportable Spills	1	0	0	4.0 %	4.00 %
Mandatory Electric Reliability Standards	Non-Critical Infrastructure Protection Compliance	1+ (if minimal penalty)	0	0	3.0 %	3.00 %
	Critical Infrastructure Protection Compliance	1+ (if minimal penalty)	0	0	3.0 %	3.00 %
Financial						
Cost Saving	Current Year / Long-Term Savings	$ 0	$50,000,000	$59,266,050	14.0 %	14.00 %
	Additional Cost Savings	$ 0	$50,000,000	$50,000,000	0-5.0%	5.00 %
Internal Control over Financial Reporting	Significant Deficiency or Material Weakness	0	0	0	2.0 %	2.00 %
	Control Deficiency	2	1	0	2.0 %	2.00 %
Quality						
Board Satisfaction	Board of Directors Survey	80.0 %	100.0 %	94.0 %	15.0 %	14.11 %
Total					**100.0 %**	**93.20 %**

(1) Certain sub-goals are aggregated for purposes of the table.

(2) Operations goals apply to individual units of each generation facility. The thresholds and performance results provided in this summary table are aggregated based on all of the generating units within the category.

As noted above, we achieved 93.20% of our corporate goals for 2022. As a result, each of our executive officers received performance pay in an amount equal to 93.20% of 20% of his or her base salary. Set forth below is a table showing performance pay figures for each of our executive officers who received performance pay in 2022[(1)]:

Executive Officer	Performance Pay*
Michael L. Smith	$ 178,379
Elizabeth B. Higgins	103,452
David W. Sorrick	88,851
William F. Ussery	78,661
Annalisa M. Bloodworth	75,492

* Performance pay was calculated based on base salaries as of December 31, 2022. Actual compensation earned in 2022 is reported in the Summary Compensation Table below.

(1) Mr. Price retired during 2022 and was not eligible for performance pay.

Employment Agreements

General

We have an employment agreement with Mr. Smith, Ms. Higgins, Mr. Sorrick, Mr. Ussery and Ms. Bloodworth. We negotiated each of these employment agreements on an arms-length basis, and the compensation committee determined that the terms of each agreement are reasonable and necessary to ensure that these executive officers' goals are aligned with our members' interests and that each performs his or her respective role while acting in our members' best interests. We review these agreements on an annual basis.

Our employment agreement with Mr. Smith extends through December 31, 2025. Mr. Smith's agreement will automatically renew pursuant to the corresponding provision of the agreement for successive one-year periods unless either party provides written notice not to renew the agreement twenty-four months before the expiration of any extended term. Each year, our board of directors makes an affirmative determination as to whether to provide such notice and no such notice has been provided. Mr. Smith's minimum annual base salary under his agreement is $956,970, and is subject to review and adjustment by our board of directors. Mr. Smith is eligible to participate in incentive compensation plans generally available to similarly situated employees and for an annual bonus determined by our board of directors at its sole discretion. Mr. Smith is also entitled to an automobile or an automobile allowance during the term of the agreement. Mr. Smith's employment agreement contains severance pay provisions.

We also have employment agreements with Ms. Higgins, Mr. Sorrick, Mr. Ussery and Ms. Bloodworth. The current term of Ms. Higgins', Mr. Sorrick's, Mr. Ussery's and Ms. Bloodworth's agreements extends through December 31, 2025 and will automatically renew for successive one-year periods unless either party provides written notice not to renew the agreement twenty-four months before the expiration of any extended term. Each year, our president and chief executive officer makes an affirmative determination as to whether to provide such notice, and no such notices have been provided.

Minimum annual base salaries under these agreements are $555,000 for Ms. Higgins, $520,000 for Mr. Sorrick, $422,000 for Mr. Ussery and $405,000 for Ms. Bloodworth. Salaries are subject to review and possible adjustment as determined by the president and chief executive officer. Each executive is also eligible to participate in incentive compensation plans generally available to similarly situated employees and for an annual bonus determined by the president and chief executive officer at his sole discretion. The employment agreements with Ms. Higgins, Mr. Sorrick, Mr. Ussery and Ms. Bloodworth contain severance pay provisions.

On October 11, 2021, we entered into a transition agreement with Mr. Price to promote the orderly transition of responsibilities from Mr. Price to a successor chief operating officer following Mr. Price's anticipated retirement. Mr. Price retired on May 31, 2022. Pursuant to the terms of the transition agreement, Mr. Price received separation payments of $1,073,443, which represented two times his base salary plus the value of a COBRA subsidy for one year which are comparable to the severance benefits under Mr. Price's employment agreement at the time of entering into the transition agreement. As part of the transition agreement, Mr. Price agreed not to compete or work in the electric energy for four years following his retirement, subject to the repayment of the separation payments.

Assessment of Severance Arrangements

Pursuant to their respective employment agreements, certain of our executive officers are entitled to severance payments and benefits in the event they are terminated not for cause or they resign for good reason.

In determining that the president and chief executive officer's employment agreement was appropriate and necessary, the compensation committee considered Mr. Smith's role and responsibility within Oglethorpe in relation to the total amount of severance pay he would receive upon the occurrence of a severance event. The committee also considered whether the amount Mr. Smith would receive upon severance was appropriate given his total annual compensation. Upon review, the compensation committee determined that a maximum amount of severance compensation equal to a maximum of two year's compensation, plus benefits as described below, was an appropriate amount of severance compensation for Mr. Smith. The compensation committee believes that entering into a severance agreement with our president and chief executive officer is beneficial because it gives us a measure of stability in this position while affording us the flexibility to change management with minimal disruption, should our board of directors ever determine such a change to be necessary and in our best interests. The compensation committee considers an amount equal to up to two years of compensation and benefits to be an appropriate amount to address competitive concerns and offset any potential risk Mr. Smith faces in his role as our president and chief executive officer. Furthermore, it should be noted that we do not compensate our president and chief executive officer using options or other forms of equity compensation that typically lead to significant wealth accumulation.

Pursuant to the terms of his employment agreement, Mr. Smith will be entitled to a lump-sum severance payment upon the occurrence of any of the following events: (1) we terminate his employment without cause; or (2) he resigns due to a demotion or material reduction of his position or responsibilities, a material reduction of his base salary, or a relocation of his principal office by more than 50 miles. The severance payment will equal Mr. Smith's then current base salary through the rest of the term of the agreement (with a minimum of one year's pay and a maximum of two years' pay), and is payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. In addition, Mr. Smith will be entitled to outplacement services and an amount equal to his costs for medical and dental continuation coverage under COBRA, each for the longer of one year or the remaining term of the agreement. Severance is payable only if Mr. Smith signs a form releasing all claims against us. The maximum severance that would be payable to Mr. Smith in the circumstances described above is $2,139,880.

Our president and chief executive officer considered the total amount of compensation Ms. Higgins, Mr. Sorrick, Mr. Ussery and Ms. Bloodworth would receive upon the occurrence of a severance event and determined that it was appropriate for these executive officers to receive severance compensation equal to a maximum of two years of his or her then current base salary, plus benefits as described below, because such agreements provide a measure of stability for both us and the executive officers. In addition, like our president and chief executive officer, these executive officers are not compensated using options or other forms of equity compensation that lead to significant wealth accumulation. Therefore, our president and chief executive officer believes such severance compensation is necessary to address competitive concerns and offset any potential risk our executive officers face in the course of their employment.

Pursuant to the terms of their employment agreements, Ms. Higgins, Mr. Sorrick, Mr. Ussery and Ms. Bloodworth will each be entitled to a lump-sum severance payment if we terminate the executive without cause or if the executive resigns after a demotion or material reduction of his or her position or responsibilities, a reduction of his or her base salary, or a relocation of his or her principal office by more than 50 miles. The severance payment will equal the executive officer's then current base salary through the rest of the term of the agreement (with a minimum of one year's pay and a maximum of two years' pay), payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. In addition, the executive will be entitled to one year of outplacement services and an amount equal to the executive's cost for medical and dental continuation coverage under COBRA for one year. Severance is payable only if the executive signs a form releasing all claims against us. The maximum severance that would be payable to Ms. Higgins, Mr. Sorrick, Mr. Ussery and Ms. Bloodworth in the circumstances described above is $1,229,260, $1,125,831, $934,688 and $934,017, respectively.

Compensation Committee Report

The Compensation Committee of Oglethorpe Power Corporation has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2022 for filing with the SEC.

Respectfully Submitted
The Compensation Committee

Earnest A. Jakins III
Jimmy G. Bailey
Fred A. McWhorter
Danny L. Nichols
Horace H. Weathersby III

Compensation Committee Interlocks and Insider Participation

Mr. Jakins, Mr. Bailey, Mr. McWhorter, Mr. Millwood, Mr. Nichols and Mr. Weathersby served as members of our compensation committee during all or a portion of 2022.

Mr. Jakins is a director of ours and the President and Chief Executive Officer of Jackson Electric Membership Corporation. Jackson is a member of ours and has a wholesale power contract with us. Jackson's revenues of $339.9 million to us in 2022 under its wholesale power contract accounted for approximately 16.0% of our total revenues.

Mr. Nichols is a director of ours and is the General Manager of Colquitt Electric Membership Corporation. Colquitt is a member of ours and has a wholesale power contract with us. Colquitt's revenues of $59.9 million to us in 2022 under its wholesale power contract accounted for approximately 2.8% of our total revenues.

Summary Compensation Table

The following table sets forth the total compensation paid or earned by each of our executive officers for the fiscal years ended December 31, 2022, 2021 and 2020.

Name and Principal Position	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	All Other Compensation(1)	Total
Michael L. Smith	2022	$ 947,475	$ —	$ 178,379	$ 186,873	$ 1,312,727
President and	2021	890,140	—	166,176	177,508	1,233,824
Chief Executive Officer	2020	833,854	—	160,886	166,731	1,161,471
Michael W. Price(2)	2022	178,390	—	—	1,230,799	1,409,189
Former Executive Vice President	2021	515,333	—	95,644	107,182	718,159
and Chief Operating Officer	2020	480,501	—	96,053	101,764	678,318
Elizabeth B. Higgins	2022	549,167	—	103,452	113,797	766,416
Executive Vice President and	2021	517,333	—	96,013	108,579	721,925
Chief Financial Officer	2020	486,547	—	96,435	102,427	685,409
David W. Sorrick(3)	2022	484,168	—	88,851	110,233	683,252
Executive Vice President and						
Chief Operating Officer						
William F. Ussery	2022	417,833	—	78,661	97,440	593,934
Executive Vice President,	2021	395,000	—	73,302	83,332	551,634
Member Relations	2020	375,231	—	73,666	81,806	530,703
Annalisa M. Bloodworth	2022	390,750	—	75,492	95,858	562,100
Senior Vice President,						
and General Counsel						

(1) Figures for 2022 consist of matching contributions and contributions made by Oglethorpe under the 401(k) Retirement Savings Plan on behalf of each Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Ms. Bloodworth of $40,500 and $32,733 for Mr. Sorrick; contributions by Oglethorpe to a nonqualified deferred compensation plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Ms. Bloodworth, respectively of $126,071,

$15,692, $57,568, $36,344 and $30,251; transition payment of $1,073,443 to Mr. Price, relocation payments to Mr. Sorrick of $65,000; car allowances; paid time off, executive health benefits; customary holiday gifts and service awards.

(2) Mr. Price retired on May 31, 2022.

(3) Mr. Sorrick joined Oglethorpe on February 9, 2022.

The following table sets forth the threshold and maximum awards available to the executive officers listed in the Summary Compensation Table who received performance pay for the fiscal year ended December 31, 2022.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards	
Name[(1)]	**Grant Date**	**Threshold**	**Maximum**
Michael L. Smith	N/A	$ 53,612	$ 191,394
Elizabeth B. Higgins	N/A	$ 31,093	$ 111,000
David W. Sorrick	N/A	$ 26,704	$ 95,333
William F. Ussery	N/A	$ 23,642	$ 84,400
Annalisa M. Bloodworth	N/A	$ 22,689	$ 81,000

For an explanation of the criteria and formula used to determine the awards listed above, please refer to "– Compensation Discussion and Analysis – *Assessment of Performance of 2022 Corporate Goals*."

(1) Mr. Price retired during 2022 and was not eligible for performance pay.

Nonqualified Deferred Compensation

We maintain a Fidelity Non-Qualified Deferred Compensation Program for each of the executive officers in the table below. This non-qualified deferred compensation program serves as a vehicle through which we can continue our employer retirement contributions to our executive officers beyond the IRS salary limits on the retirement plan ($305,000 as indexed).

The following table sets forth contributions for the fiscal year ended December 31, 2022 along with aggregate earnings for the same period.

Name	**Executive Contributions in Last FY**	**Registrant Contributions in Last FY[(1)]**	**Aggregate Earnings (Loss) in Last FY[(2)]**	**Aggregate Withdrawals/ Distributions in Last FY**	**Aggregate Balance at Last FYE**
Michael L. Smith	$ 39,000	$ 126,071	$ (229,622)	$ —	$ 1,272,230
Elizabeth B. Higgins	$ 12,480	$ 57,568	$ (203,388)	$ —	$ 811,214
William F. Ussery	$ 3,000	$ 36,344	$ (67,727)	$ —	$ 358,220
Annalisa M. Bloodworth	$ 5,888	$ 30,251	$ (26,220)	$ —	$ 150,166
Former Executive Officer:					
Michael W. Price	$ —	$ 15,692	$ (60,570)	$ (732,719)	$ —

(1) All registrant contribution amounts shown have been included in the "All Other Compensation" column of the Summary Compensation Table above and are limited to the Fidelity Non-Qualified Deferred Compensation Program.
(2) A participant's accounts under the deferred compensation program are invested in the investment options selected by the participant. The accounts are credited with gains and losses actually experienced by the investments.

Pay Ratio Disclosure

We strive to provide fair and equitable compensation to each of our employees through a combination of competitive base pay, performance incentives, retirement plans and other benefits. The following pay ratio and supporting information compares the annual total compensation of Mr. Smith, our president and chief executive officer, to the annual total compensation of our median employee for the fiscal year ended December 31, 2022.

To identify our median employee, we determined that as of December 31, 2022, we had 323 employees, including full-time, part-time, temporary and seasonal workers (excluding our president and chief executive officer), who were all located in the United States. We then calculated the annual total compensation for each of these employees for the fiscal year ended December 31, 2022 in the same manner in which we calculated our president and chief executive officer's total annual compensation presented in the "Summary Compensation Table." Employee compensation includes salary, performance pay and benefits.

Based upon this analysis, we determined that our median employee's annual total compensation for 2022 was $166,561. As set forth in the Summary Compensation Table, our president and chief executive officer's annual total compensation for 2022 was $1,312,727. The ratio of our president and chief executive officer's annual total compensation to our median employee's annual total compensation for the fiscal year ended December 31, 2022 was 7.88:1.

Compensation Policies and Practices As They Relate to Our Risk Management

We believe that our compensation policies and practices for all employees, including executive officers, do not create risks that are reasonably likely to have a material adverse effect on us.

Director Compensation

The following table sets forth the total compensation paid or earned by each of our directors for the fiscal year ended December 31, 2022.

Name		Total Fees Earned or Paid in Cash
Member Directors		
Jimmy G. Bailey	$	17,680
Randy Crenshaw	$	16,770
Ernest A. "Chip" Jakins III	$	13,390
Fred A. McWhorter	$	11,700
Marshall S. Millwood, Chairman	$	22,412
Jeffrey W. Murphy	$	16,770
Danny L. Nichols	$	16,380
Sammy G. Simonton	$	19,710
Horace H. Weathersby III(1)	$	13,100
George L. Weaver	$	17,530
James I. White, Vice-Chairman	$	22,100
Outside Director		
Wm. Ronald Duffey	$	32,810

(1) Mr. Weathersby was elected to our board of directors in March 2022.

In 2022, we paid our member directors a fee of $1,560 per board meeting and $1,040 per day for attending committee meetings, other meetings, or other official business approved by the chairman of the board of directors. Member directors were paid $780 per day for attending the annual meeting of members and member advisory board meetings and $390 per day for participation by video conference for a meeting of the advisory board. We paid our outside director a fee of $5,500 per board meeting for four meetings a year and a fee of $1,000 per board meeting for the remaining board meetings held during the year. Our outside director was also paid $1,000 per day for attending committee meetings, annual meetings of the members or other official business. In addition, we reimburse all directors for out-of-pocket expenses incurred in attending a meeting. All directors, including the outside director, were paid $130 per hour, or for each fraction thereof, up to a daily cap of $780, when participating in meetings by conference call. The chairman of the board of directors is paid an additional 20% of his director's fee per board meeting for time involved in preparing for the meetings. The audit committee financial expert is paid an additional $400 per audit committee meeting for the time involved in fulfilling that role. If more than one meeting is held the same day, only one day's per diem is paid. Neither our outside director nor member directors receive any perquisites or other personal benefits from us.

Through June 6, 2022, we paid our directors $600 per day, travel and out-of-pocket expenses for attending external training. We also paid any fees charged for such training. Directors may have chosen one external training course per year to attend. Our board of directors approved an increase in compensation for external training and the number of external training courses our directors are compensated for attending, effective after June 6, 2022. Subsequent to June 6, 2022, directors may choose up to three external training courses related to their role as director and/or the energy industry per year to attend. Our directors will continue to be paid $600 per day for each day of an external training course plus, where applicable, up to two additional days for time spent traveling to and from an external training course. Directors will continue to be reimbursed for travel and out-of-pocket expenses for attending external training.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

Randy Crenshaw is a director of ours and the President and Chief Executive Officer of Irwin Electric Membership Corporation and Middle Georgia Electric Membership Corporation. Irwin and Middle Georgia are members of ours and each has a wholesale power contract with us. Irwin's revenues of $9.8 million to us in 2022 under its wholesale power contract accounted for approximately 0.5% of our total revenues. Middle Georgia's revenues of $6.4 million to us in 2022 under its wholesale power contract accounted for approximately 0.3% of our total revenues.

Chip Jakins is a director of ours and the President and Chief Executive Officer of Jackson Electric Membership Corporation. Jackson is a member of ours and has a wholesale power contract with us. Jackson's revenues of $339.9 million to us in 2022 under its wholesale power contract accounted for approximately 16.0% of our total revenues.

Jeffrey Murphy is a director of ours and the President and Chief Executive Officer of Hart Electric Membership Corporation. Hart is a member of ours and has a wholesale power contract with us. Hart's revenues of $26.7 million to us in 2022 under its wholesale power contract accounted for approximately 1.3% of our total revenues.

Danny Nichols is a director of ours and is the General Manager of Colquitt Electric Membership Corporation. Colquitt is a member of ours and has a wholesale power contract with us. Colquitt's revenues of $59.9 million to us in 2022 under its wholesale power contract accounted for approximately 2.8% of our total revenues.

George Weaver is a director of ours and the President and Chief Executive Officer of Central Georgia Electric Membership Corporation. Central Georgia is a member of ours and has a wholesale power contract with us. Central Georgia's revenues of $100.3 million to us in 2022 under its wholesale power contract accounted for approximately 4.7% of our total revenues.

We have a Standards of Conduct/Conflict of Interest policy that sets forth guidelines that our employees and directors must follow in order to avoid conflicts of interest, or any appearance of conflicts of interest, between an individual's personal interests and our interests. Pursuant to this policy, each employee and director must disclose any conflicts of interest, actions or relationships that might give rise to a conflict. Our president and chief executive officer is responsible for taking reasonable steps to ensure that the employees are complying with this policy and the audit committee is responsible for taking reasonable steps to ensure that the directors are complying with this policy. The audit committee is charged with monitoring compliance with this policy and making recommendations to the board of directors regarding this policy. Certain actions or relationships that might give rise to a conflict of interest are reviewed and approved by our board of directors.

Director Independence

Because we are an electric cooperative, our members own and manage us. Our bylaws set forth specific requirements regarding the composition of our board of directors. See "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE – Our Board of Directors – *Structure of Our Board of Directors*" for a detailed discussion of the specific requirements contained in our bylaws regarding the composition of our board of directors.

In addition to meeting the requirements set forth in our bylaws, all directors, with the exception of Chip Jakins, satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet the requirements set forth in our bylaws. Mr. Jakins does not qualify as an independent director because he is the President and Chief Executive Officer of Jackson Electric Membership Corporation, an organization from which we received more than 5% of our gross revenues for the fiscal year ended December 31, 2022. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria in making this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For 2022 and 2021, fees for services provided by our independent registered public accounting firm, Ernst & Young LLP were as follows:

	2022	2021
	(dollars in thousands)	
Audit Fees[1]	**$ 706**	$ 550
Audit-Related Fees[2]	**162**	103
Tax Fees[3]	**—**	30
All Other Fees[4]	**2**	1
Total	**$ 870**	$ 684

(1) Audit of annual financial statements and review of financial statements included in SEC filings and services rendered in connection with financings.
(2) Other audit-related services.
(3) Professional tax services including tax consultation and tax return compliance.
(4) All other fees relate to a subscription of an on-line accounting research and investigative tool.

In considering the nature of the services provided by our independent registered public accounting firm, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed all non-audit services to be provided by independent registered public accounting firm to us with management prior to approving them to confirm that they were non-audit services permitted to be provided by our independent registered public accounting firm.

Pre-Approval Policy

The audit and permissible non-audit services performed by Ernst & Young LLP in 2022 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. The policy requires that requests for all services must be submitted to the audit committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of Documents Filed as a Part of This Report.

(1) Financial Statements (Included under "Financial Statements and Supplementary Data")

(2) Financial Statement Schedules

None applicable.

(3) Exhibits

Exhibits marked with an asterisk (*) are hereby incorporated by reference to exhibits previously filed by the Registrant as indicated in parentheses following the description of the exhibit.

Number		Description
*3.1(a)	–	Restated Articles of Incorporation of Oglethorpe, dated as of July 26, 1988. (Filed as Exhibit 3.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*3.1(b)	–	Amendment to Articles of Incorporation of Oglethorpe, dated as of March 11, 1997. (Filed as Exhibit 3(i)(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*3.2	–	Bylaws of Oglethorpe, as amended and restated, as of December 6, 2016. (Filed as Exhibit 3.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 2016, File No. 000-53908.)
*4.1	–	Twelfth Amended and Restated Loan Contract, dated as of October 18, 2022, between Oglethorpe and the United States of America. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2022, File No. 333-192954.)
*4.2.1(a)	–	Indenture, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. (Filed as Exhibit 4.8.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.2.1(b)	–	First Supplemental Indenture, dated as of October 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1997B (Burke) Note. (Filed as Exhibit 4.8.1(b) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1997, File No. 33-7591.)
*4.2.1(c)	–	Second Supplemental Indenture, dated as of January 1, 1998, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1997C (Burke) Note. (Filed as Exhibit 4.7.1(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1997, File No. 33-7591.)
*4.2.1(d)	–	Third Supplemental Indenture, dated as of January 1, 1998, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1997A (Monroe) Note. (Filed as Exhibit 4.7.1(d) to the Registrant's Form 10-K for the fiscal year December 31, 1997, File No. 33-7591.)
*4.2.1(e)	–	Fourth Supplemental Indenture, dated as of March 1, 1998, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998A (Burke) and 1998B (Burke) Notes. (Filed as Exhibit 4.7.1(e) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.2.1(f)	–	Fifth Supplemental Indenture, dated as of April 1, 1998, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998 CFC Note. (Filed as Exhibit 4.7.1(f) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.2.1(g)	–	Sixth Supplemental Indenture, dated as of January 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998C (Burke) Note. (Filed as Exhibit 4.7.1(g) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.2.1(h)	–	Seventh Supplemental Indenture, dated as of January 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998A (Monroe) Note. (Filed as Exhibit 4.7.1(h) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.2.1(i)	–	Eighth Supplemental Indenture, dated as of November 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999B (Burke) Note. (Filed as Exhibit 4.7.1(i) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.2.1(j)	–	Ninth Supplemental Indenture, dated as of November 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999B (Monroe) Note. (Filed as Exhibit 4.7.1(j) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.2.1(k)	–	Tenth Supplemental Indenture, dated as of December 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999 Lease Notes. (Filed as Exhibit 4.7.1(k) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)

*4.2.1(l)	–	Eleventh Supplemental Indenture, dated as of January 1, 2000, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1999A (Burke) Note. (Filed as Exhibit 4.7.1(l) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.2.1(m)	–	Twelfth Supplemental Indenture, dated as of January 1, 2000, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1999A (Monroe) Note. (Filed as Exhibit 4.7.1(m) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.2.1(n)	–	Thirteenth Supplemental Indenture, dated as of January 1, 2001, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2000 (Burke) Note. (Filed as Exhibit 4.7.1(n) to the Registrant's Form 10-K for the fiscal year ended December 31, 2000, File No. 33-7591.)
*4.2.1(o)	–	Fourteenth Supplemental Indenture, dated as of January 1, 2001, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2000 (Monroe) Note. (Filed as Exhibit 4.7.1(o) to the Registrant's Form 10-K for the fiscal year ended December 31, 2000, File No. 33-7591.)
*4.2.1(p)	–	Fifteenth Supplemental Indenture, dated as of January 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2001 (Burke) Note. (Filed as Exhibit 4.7.1(p) to the Registrant's Form 10-K for the fiscal year ended December 31, 2001, File No. 33-7591.)
*4.2.1(q)	–	Sixteenth Supplemental Indenture, dated as of January 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2001 (Monroe) Note. (Filed as Exhibit 4.7.1(q) to the Registrant's Form 10-K for the fiscal year ended December 31, 2001, File No. 33-7591.)
*4.2.1(r)	–	Seventeenth Supplemental Indenture, dated as of October 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002A (Burke) Note. (Filed as Exhibit 4.7.1(r) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.2.1(s)	–	Eighteenth Supplemental Indenture, dated as of October 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002B (Burke) Note. (Filed as Exhibit 4.7.1(s) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.2.1(t)	–	Nineteenth Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002C (Burke) Note. (Filed as Exhibit 4.7.1(t) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.2.1(u)	–	Twentieth Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002 (Monroe) Note. (Filed as Exhibit 4.7.1(u) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.2.1(v)	–	Twenty-First Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002 (Appling) Note. (Filed as Exhibit 4.7.1(v) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.2.1(w)	–	Twenty-Second Supplemental Indenture, dated as of March 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003 (FFB M-8) Note and Series 2003 (RUS M-8) Reimbursement Note. (Filed as Exhibit 4.7.1(w) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003, File No. 33-7591.)
*4.2.1(x)	–	Twenty-Third Supplemental Indenture, dated as of March 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003 (FFB N-8) Note and Series 2003 (RUS N-8) Reimbursement Note. (Filed as Exhibit 4.7.1(x) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003, File No. 33-7591.)
*4.2.1(y)	–	Twenty-Fourth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Appling) Note. (Filed as Exhibit 4.7.1(y) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.2.1(z)	–	Twenty-Fifth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Burke) Note. (Filed as Exhibit 4.7.1(z) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)

*4.2.1(aa)	–	Twenty-Sixth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003B (Burke) Note. (Filed as Exhibit 4.7.1(aa) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.2.1(bb)	–	Twenty-Seventh Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Heard) Note. (Filed as Exhibit 4.7.1(bb) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.2.1(cc)	–	Twenty-Eighth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Monroe) Note. (Filed as Exhibit 4.7.1(cc) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.2.1(dd)	–	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2004, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2004 (Burke) Note. (Filed as Exhibit 4.7.1(dd) to the Registrant's Form 10-K for the fiscal year ended December 31, 2004, File No. 33-7591.)
*4.2.1(ee)	–	Thirtieth Supplemental Indenture, dated as of December 1, 2004, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2004 (Monroe) Note. (Filed as Exhibit 4.7.1(ee) to the Registrant's Form 10-K for the fiscal year ended December 31, 2004, File No. 33-7591.)
*4.2.1(ff)	–	Thirty-First Supplemental Indenture, dated as of November 1, 2005, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2005 (Burke) Note. (Filed as Exhibit 4.7.1(ff) to the Registrant's Form 10-K for the fiscal year ended December 31, 2005, File No. 33-7591.)
*4.2.1(gg)	–	Thirty-Second Supplemental Indenture, dated as of November 1, 2005, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2005 (Monroe) Note. (Filed as Exhibit 4.7.1(gg) to the Registrant's Form 10-K for the fiscal year ended December 31, 2005, File No. 33-7591.)
*4.2.1(hh)	–	Thirty-Third Supplemental Indenture, dated as of May 1, 2006, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2006 (FFB P-8) Note and Series 2006 (RUS P-8) Reimbursement Note. (Filed as Exhibit 4.7.1(hh) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006, File No. 33-7591.)
*4.2.1(ii)	–	Thirty-Fourth Supplemental Indenture, dated as of September 22, 2006, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Amendment of Section 9.9 of the Original Indenture. (Filed as Exhibit 4.7.1(ii) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.2.1(jj)	–	Thirty-Fifth Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2006. (Filed as Exhibit 4.7.1(jj) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.2.1(kk)	–	Thirty-Sixth Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2006A (Burke) Note, Series 2006B-1 (Burke) Note, Series 2006B-2 (Burke) Note, Series 2006B-3 (Burke) Note, Series 2006B-4 (Burke) Note and Series 2006A (Monroe) Note. (Filed as Exhibit 4.7.1(kk) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.2.1(ll)	–	Thirty-Seventh Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2006C-1 (Burke) Note, Series 2006C-2 (Burke) Note and Series 2006B (Monroe) Note. (Filed as Exhibit 4.7.1(ll) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.2.1(mm)	–	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Amendments to the Retained Indebtedness Note. (Filed as Exhibit 4.7.1(mm) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2007, File No. 33-7591.)
*4.2.1(nn)	–	Thirty-Ninth Supplemental Indenture, dated as of July 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2007 (FFB R-8) Note and Series 2007 (RUS R-8) Reimbursement Note. (Filed as Exhibit 4.7.1(nn) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2007, File No. 33-7591.)

*4.2.1(oo)	–	Fortieth Supplemental Indenture, dated as of October 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2007. (Filed as Exhibit 4.7.1(oo) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2007, File No. 33-7591.)
*4.2.1(pp)	–	Forty-First Supplemental Indenture, dated as of October 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2007A (Appling) Note, Series 2007B (Appling) Note, Series 2007A (Burke) Note, Series 2007B (Burke) Note, Series 2007C (Burke) Note, Series 2007D (Burke) Note, Series 2007E (Burke) Note, Series 2007F (Burke) Note and Series 2007A (Monroe) Note. (Filed as Exhibit 4.7.1(pp) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2007, File No. 33-7591.)
*4.2.1(qq)	–	Forty-Second Supplemental Indenture, dated as of February 5, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, providing for the Amendment of Section 1.1 of the Original Indenture. (Filed as Exhibit 4.7.1(qq) to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.)
*4.2.1(rr)	–	Forty-Third Supplemental Indenture, dated as of August 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008A (Burke) Note, Series 2008B (Burke) Note and Series 2008C (Burke) Note. (Filed as Exhibit 4.7.1(rr) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.2.1(ss)	–	Forty-Fourth Supplemental Indenture, dated as of September 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008 (FFB S-8) Note and Series 2008 (RUS S-8) Reimbursement Note. (Filed as Exhibit 4.7.1(ss) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.2.1(tt)	–	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008D (Burke) Note, Series 2008E (Burke) Note, Series 2008F (Burke) Note, Series 2008G (Burke) Note and Series 2008A (Monroe) Note. (Filed as Exhibit 4.7.1(tt) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.2.1(uu)	–	Forty-Sixth Supplemental Indenture, dated as of February 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2009 A. (Filed as Exhibit 4.7.1(uu) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.2.1(vv)	–	Forty-Seventh Supplemental Indenture, dated as of February 19, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, providing for the Amendment of the Original Indenture. (Filed as Exhibit 4.7.1(vv) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.2.1(ww)	–	Forty-Eighth Supplemental Indenture, dated as of August 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009B CFC Note, Series 2009C CFC Note and Series 2009D CFC Project Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2009, File No. 333-159338.)
*4.2.1(xx)	–	Forty-Ninth Supplemental Indenture, dated as of November 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2009 B. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarter ended September 30, 2009, File No. 333-159338.)
*4.2.1(yy)	–	Fiftieth Supplemental Indenture, dated as of November 30, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009A Line of Credit Notes. (Filed as Exhibit 4.7.1 (yy) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*4.2.1 (zz)	–	Fifty-First Supplemental Indenture, dated as of December 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009A (Heard) Note, Series 2009A (Monroe) Note and Series 2009B (Monroe) Note. (Filed as Exhibit 4.7.1 (zz) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*4.2.1 (aaa)	–	Fifty-Second Supplemental Indenture, dated as of December 30, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond). (Filed as Exhibit 4.7.1 (aaa) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)

*4.2.1 (bbb)	–	Fifty-Third Supplemental Indenture, dated as of March 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010A (Burke) Note, Series 2010B (Burke) Note, Series 2010A (Monroe) Note, Series 2010A (Burke) Reimbursement Obligation, Series 2010B (Burke) Reimbursement Obligation and Series 2010A (Monroe) Reimbursement Obligation. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010, File No. 000-53908.)
*4.2.1 (ccc)	–	Fifty-Fourth Supplemental Indenture, dated as of May 21, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, confirming the lien of the Indenture with respect to certain After-Acquired Property (relating to the Hawk Road and Hartwell Energy Facilities). (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2010, File No. 000-53908.)
*4.2.1 (ddd)	–	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010 (FFB V-8) Note and Series 2010 (RUS V-8) Reimbursement Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2010, File No. 000-53908.)
*4.2.1 (eee)	–	Fifty-Sixth Supplemental Indenture, dated as of November 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2010 A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 8, 2010, File No. 000-53908.)
*4.2.1(fff)	–	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010A CFC Note. (Filed as Exhibit 4.8.1(fff) to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
*4.2.1(ggg)	–	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Agreement Modifying Future Advance Promissory Note. (Filed as Exhibit 4.8.1(ggg) to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
*4.2.1(hhh)	–	Fifty-Ninth Supplemental Indenture, dated as of March 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2011A (Appling) Note, Series 2011A (Burke) Note and Series 2011A (Monroe) Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.2.1(iii)	–	Sixtieth Supplemental Indenture, dated as of April 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2011 (FFB W-8) Note, Series 2011 (RUS W-8) Reimbursement Note, Series 2011 (FFB X-8) Note, and Series 2011 (RUS X-8) Reimbursement Note. (Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.2.1(jjj)	–	Sixty-First Supplemental Indenture, dated as of August 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2011A. (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2011, File No. 000-53908.)
*4.2.1(kkk)	–	Sixty-Second Supplemental Indenture, dated as of April 1, 2012, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2012A (Monroe) Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2012, File No. 000-53908.)
*4.2.1(lll)	–	Sixty-Third Supplemental Indenture, dated as of November 1, 2012, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2012A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 28, 2012, File No. 000-53908.)
*4.2.1(mmm)	–	Sixty-Fourth Supplemental Indenture, dated as of April 1, 2013, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2013A (Appling) Note, Series 2013A (Burke) Note and Series 2013A (Monroe) Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.)
*4.2.1(nnn)	–	Sixty-Fifth Supplemental Indenture, dated as of April 23, 2013, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2013 (FFB Y-8) Note, Series 2013 (RUS Y-8) Reimbursement Note, Series 2013 (FFB AA-8) Note, and Series 2013 (RUS AA-8) Reimbursement Note and amendments to the Indenture. (Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.)

*4.2.1(ooo)	–	Deed to Secure Debt, Security Agreement and Sixty-Sixth Supplemental Indenture, dated as of April 25, 2013, made by Oglethorpe and Murray County Industrial Development Authority to U.S. Bank National Association, as trustee, relating to the consolidation of Murray I and II LLC. (Filed as Exhibit 4.4 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.)
*4.2.1(ppp)	–	Sixty-Seventh Supplemental Indenture, dated as of February 1, 2014, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Future Advance Promissory Note No. 1, Reimbursement Note No. 1, Future Advance Promissory Note No. 2, Reimbursement Note No. 2 and amendments to the Indenture. (Filed as Exhibit 4.8 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.2.1(qqq)	–	Sixty-Eighth Supplemental Indenture, dated as of June 1, 2014 made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2014A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on June 11, 2014, File No. 000-53908.)
*4.2.1(rrr)	–	Sixty-Ninth Supplemental Indenture, dated as of September 2, 2014 made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2014 (FFB AB-8) Note and Series 2014 (RUS AB-8) Reimbursement Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2014, File No. 000-53908.)
*4.2.1(sss)	–	Seventieth Supplemental Indenture, dated as of May 27, 2015, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Amendment of the Series 2011 (FFB W-8) Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2015, File No. 000-53908.)
*4.2.1(ttt)	–	Seventy-First Supplemental Indenture, dated August 24, 2015, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the addition of property in Walton County, Georgia. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2015, File No. 000-53908.)
*4.2.1(uuu)	–	Seventy-Second Supplemental Indenture, dated as of April 1, 2016, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2016A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on April 19, 2016, File No. 000-53908).
*4.2.1(vvv)	–	Seventy-Third Supplemental Indenture, dated as of July 26, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, confirming the lien of the Indenture with respect to certain agreements and licenses. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2017, File No. 333-192954.)
*4.2.1(www)	–	Seventy-Fourth Supplemental Indenture, dated as of October 1, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2017A (Burke) Note, the Series 2017B (Burke) Note, the Series 2017A (Heard) Note and the Series 2017A (Monroe) Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2017, File No. 333-192954.)
*4.2.1(xxx)	–	Seventy-Fifth Supplemental Indenture, dated as of October 18, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Amendment of the Original Indenture. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2017, File No. 333-192954.)
*4.2.1(yyy)	–	Seventy-Sixth Supplemental Indenture, dated as of December 1, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2017C (Burke) Note, the Series 2017D (Burke) Note, the Series 2017E (Burke) Note and the Series 2017F (Burke) Note. (Filed as Exhibit 4.2.1(yyy) to the Registrant's Form 10-K for the fiscal year ended December 31, 2017, File No. 333-192954.)
*4.2.1(zzz)	–	Seventy-Seventh Supplemental Indenture, dated as of January 30, 2018, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2018 (FFB AC-8) Note and Series 2018 (RUS AC-8) Reimbursement Note. (Filed as Exhibit 4.2.1(zzz) to the Registrant's Form 10-K for the fiscal year ended December 31, 2017, File No. 333-192954.)
*4.2.1(aaaa)	–	Seventy-Eighth Supplemental Indenture, dated as of October 1, 2018, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2018A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on October 30, 2018, File No. 333-192954).
*4.2.1(bbbb)	–	Seventy-Ninth Supplemental Indenture, dated as of March 1, 2019, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Future Advance Promissory Note and Reimbursement Note. (Filed as Exhibit 4.6 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.)

*4.2.1(cccc)	–	Eightieth Supplemental Indenture, dated as of August 1, 2020, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2020A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 19, 2020, File No. 333-192954.)
*4.2.1(dddd)	–	Eighty-First Supplemental Indenture, dated as of December 3, 2020, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2020 (FFB AD48) Note and Series 2020 (RUS AD48) Reimbursement Note and Amendment of the Original Indenture. (Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on December 9, 2020, File No. 333-192954.)
*4.2.1(eeee)	–	Eighty-Second Supplemental Indenture, dated as of October 6, 2021, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Recording the Indenture in Effingham County, GA. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2021, File No. 333-192954.)
*4.2.1(ffff)		Eighty-Third Supplemental Indenture, dated as of April 1, 2022, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2022A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on April 7, 2022, File No. 333-192954.)
*4.2.1(gggg)		Eighty-Fourth Supplemental Indenture, dated as of October 18, 2022, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to the Series 2022 (FFB AE48) Note, Series 2022 (RUS AE48) Reimbursement Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2022, File No. 333-192954.)
*4.2.2	–	Security Agreement, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. (Filed as Exhibit 4.8.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.3	–	Unsecured Indenture, dated as of December 22, 2010, by and between Oglethorpe and U.S. Bank National Association, as trustee. (Filed as Exhibit 4.1 to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
4.4.1(1)	–	Loan Agreement, dated as of April 1, 2013, between the Development Authority of Appling County and Oglethorpe relating to the Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical (Term Rate Bonds) loan agreements.
4.4.2(1)	–	Note, dated April 23, 2013, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of April 1, 2013, between the Development Authority of Appling County and U.S. Bank National Association relating to the Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical notes.
4.4.3(1)	–	Trust Indenture, dated as of April 1, 2013, between the Development Authority of Appling County and U.S. Bank National Association, as trustee, relating to the Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical indentures.
4.5.1(1)	–	Loan Agreement, dated as of October 1, 2017, between the Development Authority of Burke County and Oglethorpe relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical (Indexed Put Rate Bonds) loan agreements.
4.5.2(1)	–	Note, dated October 12, 2017, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of October 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical notes.
4.5.3(1)	–	Trust Indenture, dated as of October 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association, as trustee, relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical indentures.
4.5.4(1)	–	Bondholder's Agreement, dated as of October 1, 2017, by and between Oglethorpe and RBC Municipal Products, LLC, relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical bondholder's agreements.

4.6.1(1)	–	Loan Agreement, dated as of December 1, 2017, between the Development Authority of Burke County and Oglethorpe relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017C, and two other substantially identical (Fixed Rate and Term Rate Bonds) loan agreements.
4.6.2[(1)]	–	Note, dated December 28, 2017, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of December 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017C, and two other substantially identical notes.
4.6.3[(1)]	–	Trust Indenture, dated as of December 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association, as trustee, relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017C, and two other substantially identical indentures.
4.7.1[(1)]	–	Bond Purchase Agreement, dated as of December 30, 2009, between Oglethorpe and CoBank, ACB, relating to Oglethorpe Power Corporation (An Electric Membership Corporation) First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond).
4.7.2[(1)]	–	Oglethorpe Power Corporation (An Electric Membership Corporation) First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond), dated December 30, 2009, from Oglethorpe to CoBank, ACB, in the original principal amount of $16,165,400.
*4.8.1	–	Note Purchase Agreement, dated February 20, 2014, between Oglethorpe, Federal Financing Bank and United States Department of Energy. (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.8.2	–	Future Advance Promissory Note No. 1, dated February 20, 2014, from Oglethorpe to Federal Financing Bank. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.8.3	–	Future Advance Promissory Note No. 2, dated February 20, 2014, from Oglethorpe to Federal Financing Bank. (Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.8.4	–	Note Purchase Agreement, dated as of March 22, 2019, between Oglethorpe, Federal Financing Bank and the United States Department of Energy. (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.)
*4.8.5	–	Future Advance Promissory Note, dated March 22, 2019, from Oglethorpe to Federal Financing Bank. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.)
*4.8.6	–	Loan Guarantee Agreement, dated February 20, 2014, between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.4 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.8.6(a)	–	Amendment No. 1, dated as of June 4, 2015, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2017, File No. 333-192954.)
*4.8.6(b)	–	Amendment No. 2, dated as of March 9, 2016, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2017, File No. 333-192954.)
*4.8.6(c)	–	Amendment No. 3, dated as of July 27, 2017, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on July 28, 2017, File No. 333-192954.)
*4.8.6(d)	–	Amendment No. 4, dated as of December 8, 2017, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on December 11, 2017, File No. 333-192954.)
*4.8.6(e)	–	Amendment No. 5 and Waiver, dated as of March 7, 2019, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on March 13, 2019, File No. 333-192954.)
*4.8.6(f)	–	Amended and Restated Loan Guarantee Agreement, dated as of March 22, 2019, between Oglethorpe and the United States Department of Energy, acting by and through the Secretary of Energy. (Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.)

*4.8.6(g)	–	Amendment No.1 to Amended and Restated Loan Guarantee Agreement, dated December 3, 2020, between Oglethorpe and the Department of Energy. (Filed as Exhibit 4.9.6(g) to the Registrant's Form 10-K for the fiscal year ended December 31, 2020, File No. 333-192954.)
*4.8.7	–	Reimbursement Note No. 1, dated February 20, 2014, issued by Oglethorpe to the Department of Energy. (Filed as Exhibit 4.5 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.8.8	–	Reimbursement Note No. 2, dated February 20, 2014, issued by Oglethorpe to the Department of Energy. (Filed as Exhibit 4.6 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.8.9	–	Reimbursement Note, dated March 22, 2019, issued by Oglethorpe to the Department of Energy. (Filed as Exhibit 4.4 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.)
*10.1.1(a)	–	Participation Agreement No. 2 among Oglethorpe as Lessee, Wilmington Trust Company as Owner Trustee, The First National Bank of Atlanta as Indenture Trustee, Columbia Bank for Cooperatives as Loan Participant and Ford Motor Credit Company as Owner Participant, dated December 30, 1985, together with a schedule identifying three other substantially identical Participation Agreements. (Filed as Exhibit 10.1.1(b) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.1(b)	–	Supplemental Participation Agreement No. 2. (Filed as Exhibit 10.1.1(a) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.1(c)	–	Supplemental Participation Agreement No. 1, dated as of June 30, 1987, among Oglethorpe as Lessee, IBM Credit Financing Corporation as Owner Participant, Wilmington Trust Company and The Citizens and Southern National Bank as Owner Trustee, The First National Bank of Atlanta, as Indenture Trustee, and Columbia Bank for Cooperatives, as Loan Participant. (Filed as Exhibit 10.1.1(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.1(d)	–	Second Supplemental Participation Agreement No. 2, dated as of December 17, 1997, among Oglethorpe as Lessee, DFO Partnership, as assignee of Ford Motor Credit Company, as Owner Participant, Wilmington Trust Company and NationsBank, N.A. as Owner Trustee, The Bank of New York Trust Company of Florida, N.A. as Indenture Trustee, CoBank, ACB as Loan Participant, OPC Scherer Funding Corporation, as Original Funding Corporation, OPC Scherer 1997 Funding Corporation A, as Funding Corporation, and SunTrust Bank, Atlanta, as Original Collateral Trust Trustee and Collateral Trust Trustee, with a schedule identifying three substantially identical Second Supplemental Participation Agreements and any material differences. (Filed as Exhibit 10.1.1(d) to Registrant's Form S-4 Registration Statement, File No. 333-4275.)
*10.1.2	–	General Warranty Deed and Bill of Sale No. 2 between Oglethorpe, Grantor, and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Grantee, together with a schedule identifying three substantially identical General Warranty Deeds and Bills of Sale. (Filed as Exhibit 10.1.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.3	–	Amended and Restated Indenture of Trust, Deed to Secure Debt and Security Agreement No. 2, dated December 1, 1997, between Wilmington Trust Company and NationsBank, N.A. collectively as Owner Trustee, under Trust Agreement No. 2, dated December 30, 1985, with DFO Partnership, as assignee of Ford Motor Credit Company, and The Bank of New York Trust Company of Florida, N.A. as Indenture Trustee, with a schedule identifying three other substantially identical Amended and Restated Indentures of Trust, Deeds to Secure Debt and Security Agreements and any material differences. (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*10.1.4(a)	–	Lease Agreement No. 2, dated December 30, 1985, between Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Lessor, and Oglethorpe, Lessee, with a schedule identifying three other substantially identical Lease Agreements. (Filed as Exhibit 4.5(b) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.4(b)	–	First Supplement to Lease Agreement No. 2 (included as Exhibit B to the Supplemental Participation Agreement No. 2 listed as Exhibit 10.1.1(b)).

*10.1.4(c)	–	First Supplement to Lease Agreement No. 1, dated as of June 30, 1987, between The Citizens and Southern National Bank as Owner Trustee under Trust Agreement No. 1 with IBM Credit Financing Corporation, as Lessor, and Oglethorpe, as Lessee. (Filed as Exhibit 4.5(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.4(d)	–	Second Supplement to Lease Agreement No. 2, dated as of December 17, 1997, between NationsBank, N.A., acting through its agent, The Bank of New York, as an Owner Trustee under the Trust Agreement No. 2, dated December 30, 1985, among DFO Partnership, as assignee of Ford Motor Credit Company, as the Owner Participant, and the Original Trustee, as Lessor, and Oglethorpe, as Lessee, with a schedule identifying three other substantially identical Second Supplements to Lease Agreements and any material differences. (Filed as Exhibit 4.5(d) to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*10.1.5(a)	–	Supporting Assets Lease No. 2, dated December 30, 1985, between Oglethorpe, Lessor, and Wilmington Trust Company and William J. Wade, as Owner Trustees, under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Lessee, together with a schedule identifying three substantially identical Supporting Assets Leases. (Filed as Exhibit 10.1.3 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.5(b)	–	First Amendment to Supporting Assets Lease No. 2, dated as of November 19, 1987, together with a schedule identifying three substantially identical First Amendments to Supporting Assets Leases. (Filed as Exhibit 10.1.3(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.5(c)	–	Second Amendment to Supporting Assets Lease No. 2, dated as of October 3, 1989, together with a schedule identifying three substantially identical Second Amendments to Supporting Assets Leases. (Filed as Exhibit 10.1.3(c) to the Registrant's Form 10-Q for the quarterly period ended March 31, 1998, File No. 33-7591.)
*10.1.6(a)	–	Supporting Assets Sublease No. 2, dated December 30, 1985, between Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Sublessor, and Oglethorpe, Sublessee, together with a schedule identifying three substantially identical Supporting Assets Subleases. (Filed as Exhibit 10.1.4 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.6(b)	–	First Amendment to Supporting Assets Sublease No. 2, dated as of November 19, 1987, together with a schedule identifying three substantially identical First Amendments to Supporting Assets Subleases. (Filed as Exhibit 10.1.4(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.6(c)	–	Second Amendment to Supporting Assets Sublease No. 2, dated as of October 3, 1989, together with a schedule identifying three substantially identical Second Amendments to Supporting Assets Subleases. (Filed as Exhibit 10.1.4(c) to the Registrant's Form 10-Q for the quarterly period ended March 31, 1998, File No. 33-7591.)
*10.1.7(a)	–	Tax Indemnification Agreement No. 2, dated December 30, 1985, between Ford Motor Credit Company, Owner Participant, and Oglethorpe, Lessee, together with a schedule identifying three substantially identical Tax Indemnification Agreements. (Filed as Exhibit 10.1.5 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.7(b)	–	Amendment No. 1 to the Tax Indemnification Agreement No. 2, dated December 17, 1997, between DFO Partnership, as assignee of Ford Motor Credit Company, as Owner Participant, and Oglethorpe, as Lessee, with a schedule identifying three substantially identical Amendments No. 1 to the Tax Indemnification Agreements and any material differences. (Filed as Exhibit 10.1.5(b) to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*10.1.8	–	Assignment of Interest in Ownership Agreement and Operating Agreement No. 2, dated December 30, 1985, between Oglethorpe, Assignor, and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Assignee, together with a schedule identifying three substantially identical Assignments of Interest in Ownership Agreement and Operating Agreement. (Filed as Exhibit 10.1.6 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)

*10.1.9(a)	–	Consent, Amendment and Assumption No. 2, dated December 30, 1985, among Georgia Power Company and Oglethorpe and Municipal Electric Authority of Georgia and City of Dalton, Georgia and Gulf Power Company and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, together with a schedule identifying three substantially identical Consents, Amendments and Assumptions. (Filed as Exhibit 10.1.9 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.9(b)	–	Amendment to Consent, Amendment and Assumption No. 2, dated as of August 16, 1993, among Oglethorpe, Georgia Power Company, Municipal Electric Authority of Georgia, City of Dalton, Georgia, Gulf Power Company, Jacksonville Electric Authority, Florida Power & Light Company and Wilmington Trust Company and NationsBank of Georgia, N.A., as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, together with a schedule identifying three substantially identical Amendments to Consents, Amendments and Assumptions. (Filed as Exhibit 10.1.9(a) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.2.1(a)	–	Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of May 15, 1980. (Filed as Exhibit 10.6.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.2.1(b)	–	Amendment to Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 30, 1985. (Filed as Exhibit 10.1.8 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.2.1(c)	–	Amendment Number Two to the Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of July 1, 1986. (Filed as Exhibit 10.6.1(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.2.1(d)	–	Amendment Number Three to the Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of August 1, 1988. (Filed as Exhibit 10.6.1(b) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.2.1(e)	–	Amendment Number Four to the Plant Robert W. Scherer Units Number One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 31, 1990. (Filed as Exhibit 10.6.1(c) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.2.2(a)	–	Plant Robert W. Scherer Units Numbers One and Two Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of May 15, 1980. (Filed as Exhibit 10.6.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.2.2(b)	–	Amendment to Plant Robert W. Scherer Units Numbers One and Two Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 30, 1985. (Filed as Exhibit 10.1.7 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.2.2(c)	–	Amendment Number Two to the Plant Robert W. Scherer Units Numbers One and Two Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 31, 1990. (Filed as Exhibit 10.6.2(a) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.2.2(d)	–	Third Amendment to Plant Robert W. Scherer Units One and Two Operating Agreement Among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of February 22, 2022. (Filed as Exhibit 10.2.2(d) to the Registrant's Form 10-K for the fiscal year ended December 31, 2021, File No. 333-192954.)
*10.2.3	–	Plant Scherer Managing Board Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, City of Dalton, Georgia, Gulf Power Company, Florida Power & Light Company and Jacksonville Electric Authority, dated as of December 31, 1990. (Filed as Exhibit 10.6.3 to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)

*10.3.1(a)	–	Alvin W. Vogtle Nuclear Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of August 27, 1976. (Filed as Exhibit 10.7.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.3.1(b)	–	Amendment Number One, dated January 18, 1977, to the Alvin W. Vogtle Nuclear Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.7.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1986, File No. 33-7591.)
*10.3.1(c)	–	Amendment Number Two, dated February 24, 1977, to the Alvin W. Vogtle Nuclear Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.7.4 to the Registrant's Form 10-K for the fiscal year ended December 31, 1986, File No. 33-7591.)
*10.3.2	–	Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of April 21, 2006. (Filed as Exhibit 10.4.4 to the Registrant's Form 8-K, filed April 27, 2006, File No. 33-7591.)
*10.3.2(a)	–	Amendment No. 1 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement, dated as of April 8, 2008, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.3.2(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.3.2(b)	–	Agreement and Amendment No. 2 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement, dated as of February 20, 2014, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.3.2(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.3.2(c)	–	Amendment regarding Additional Participating Party Rights and Amendment No. 3 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement and Amendment No. 4 to Plant Vogtle Owners Agreement Authorizing Development, Construction, Licensing, and Operation of Additional Generating Units, dated as of November 2, 2017, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia. (Filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2017, File No. 333-192954.)
*10.3.2(d)	–	Global Amendments to Vogtle Additional Units Agreements, dated as of February 18, 2019, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia. (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on February 20, 2019, File No. 333-192954.)
*10.3.2(e)	–	Amended and Restated Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia, dated as of March 22, 2019. (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.)
*10.3.3	–	Plant Alvin W. Vogtle Nuclear Units Amended and Restated Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of April 21, 2006. (Filed as Exhibit 10.4.3 to the Registrant's Form 8-K filed on April 27, 2006, File No. 33-7591.)
*10.3.3(a)	–	Amendment No. 1 to Plant Alvin W. Vogtle Nuclear Units Amended and Restated Operating Agreement, dated as of April 8, 2008, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.3.3(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.3.3(b)	–	Agreement and Amendment No. 2 to Plant Alvin W. Vogtle Nuclear Units Amended and Restated Operating Agreement, dated as of February 20, 2014, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.3.3(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)

*10.3.4	–	Settlement Agreement dated as of June 9, 2017, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Toshiba Corporation. (Incorporated by reference to Exhibit 10.1 of Georgia Power Company's Form 8-K dated June 16, 2017, filed with the SEC on June 16, 2017.)
*10.3.4(a)	–	Settlement Agreement Amendment No. 1 to Settlement Agreement, dated December 8, 2017, among Georgia Power, Oglethorpe, the Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities and the Toshiba Corporation (Incorporated by reference to Exhibit 10.1 of Georgia Power Company's Form 8-K dated December 8, 2017, filed with the SEC on December 11, 2017.)
*10.3.5(2)	–	Amended and Restated Services Agreement, dated as of July 20, 2017, by and among Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse Electric Company LLC and WECTEC Global Project Services Inc. (Incorporated by reference to Exhibit 10(c)(9) of Georgia Power Company's Form 10-Q for the quarterly period ended June 30, 2017, filed with the SEC on August 2, 2017.)
*10.3.6(a)(2)	–	Construction Completion Agreement dated as of October 23, 2017, between Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Bechtel Power Corporation. (Incorporated by reference to Exhibit 10(c)(8) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2017, filed with the SEC on February 21, 2018.)
*10.3.6(b)(2)	–	Amendment No. 1 to Construction Completion Agreement dated as of October 12, 2018, between Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia and Bechtel Power Corporation. (Incorporated by reference to Exhibit 10(c)(10) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2018, filed with the SEC on February 20, 2019.)
*10.3.6(c)	–	Amendment No. 2 to Construction Completion Agreement dated as of November 8, 2019, between Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia and Bechtel Power Corporation. (Incorporated by reference to Exhibit 10(c)(8) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2019, filed with the SEC on February 20, 2020.)
*10.4.1	–	Edwin I. Hatch Nuclear Plant Purchase and Ownership Participation Agreement between Georgia Power Company and Oglethorpe, dated as of January 6, 1975. (Filed as Exhibit 10.9.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.4.2	–	Edwin I. Hatch Nuclear Plant Operating Agreement between Georgia Power Company and Oglethorpe, dated as of January 6, 1975. (Filed as Exhibit 10.9.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.5.1	–	Rocky Mountain Pumped Storage Hydroelectric Project Ownership Participation Agreement, dated as of November 18, 1988, by and between Oglethorpe and Georgia Power Company. (Filed as Exhibit 10.22.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*10.5.2	–	Rocky Mountain Pumped Storage Hydroelectric Project Operating Agreement, dated as of November 18, 1988, by and between Oglethorpe and Georgia Power Company. (Filed as Exhibit 10.22.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*10.6.1	–	Amended and Restated Wholesale Power Contract, dated as of January 1, 2003, between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 36 other substantially identical Amended and Restated Wholesale Power Contracts. (Filed as Exhibit 10.31.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003, File No. 33-7591.)

*10.6.2	–	First Amendment to Amended and Restated Wholesale Power Contract, dated as of June 1, 2005, between Oglethorpe and Altamaha Electric Membership Corporation, together with a scheduling identifying 35 other substantially identical First Amendments. (Filed as Exhibit 10.8.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2005, File No. 33-7591.)
*10.6.3	–	Amended and Restated Supplemental Agreement, dated as of January 1, 2003, by and among Oglethorpe, Altamaha Electric Membership Corporation and the United States of America, together with a schedule identifying 36 other substantially identical Amended and Restated Supplemental Agreements. (Filed as Exhibit 10.31.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003, File No. 33-7591.)
*10.6.4	–	Supplemental Agreement to the Amended and Restated Wholesale Power Contract, dated as of January 1, 1997, by and among Georgia Power Company, Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 36 other substantially identical Supplemental Agreements. (Filed as Exhibit 10.8.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.6.5	–	Wholesale Power Contract, dated November 1, 2009, between Oglethorpe and Flint Electric Membership Corporation. (Filed as Exhibit 10.8.8 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*10.6.6	–	Supplemental Agreement to the Wholesale Power Contract, dated as of November 1, 2009, by and between Oglethorpe, Flint Electric Membership Corporation and the United States of America. (Filed as Exhibit 10.8.9 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*10.7	–	ITSA, Power Sale and Coordination Umbrella Agreement between Oglethorpe and Georgia Power Company, dated as of November 12, 1990. (Filed as Exhibit 10.28 to the Registrant's Form 8-K, filed January 4, 1991, File No. 33-7591.)
*10.8	–	Second Amended and Restated Nuclear Managing Board Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of April 21, 2006. (Filed as Exhibit 10.13(b) to the Registrant's Form 8-K, filed April 27, 2006, File No. 33-7591.)
*10.8(a)	–	Amendment No. 1 to Second Amended and Restated Nuclear Managing Board Agreement, dated as of April 8, 2008, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton. (Filed as Exhibit 10.9(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.8(b)	–	Agreement and Amendment No. 2 to Second Amended and Restated Nuclear Managing Board Agreement, dated as of February 20, 2014, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPV J, LLC, MEAG Power SPV P, LLC, MEAG Power SPV M, LLC and City of Dalton. (Filed as Exhibit 10.9(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.9	–	Supplemental Agreement by and among Oglethorpe, Tri-County Electric Membership Corporation and Georgia Power Company, dated as of November 12, 1990, together with a schedule identifying 37 other substantially identical Supplemental Agreements. (Filed as Exhibit 10.30 to the Registrant's Form 8-K, filed January 4, 1991, File No. 33-7591.)
*10.10.1(a)	–	Member Transmission Service Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia Transmission Corporation (An Electric Membership Corporation). (Filed as Exhibit 10.33.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.10.1(b)	–	Agreement to Extend the Term of the Member Transmission Service Agreement, dated as of August 2, 2006, by and between Oglethorpe and Georgia Transmission Corporation (An Membership Corporation). (Filed as Exhibit 10.17.1(b) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006, File No. 33-7591.)
*10.10.2	–	Generation Services Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia System Operations Corporation. (Filed as Exhibit 10.33.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.10.3	–	Operation Services Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia System Operations Corporation. (Filed as Exhibit 10.33.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)

*10.11	–	Long Term Transaction Service Agreement Under Southern Companies' Federal Energy Regulatory Commission Electric Tariff Volume No. 4 Market-Based Rate Tariff, between Georgia Power Company and Oglethorpe, dated as of February 26, 1999. (Filed as Exhibit 10.27 to the Registrant's Form 10-Q for the quarterly period ended March 31, 1999, File No. 33-7591.)
*10.12	–	Amended and Restated Credit Agreement, dated as of December 11, 2019, among Oglethorpe, as borrower, and the lenders identified therein, including National Rural Utilities Cooperative Finance Corporation, as administrative agent. (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on December 11, 2019, File No. 333-192954.)
10.13(3)	–	Second Amended and Restated Employment Agreement, dated as of January 1, 2023, between Oglethorpe and Michael L. Smith.
10.14(3)	–	Third Amended and Restated Employment Agreement, dated as of January 1, 2023, between Oglethorpe and Elizabeth B. Higgins.
10.15(3)	–	Third Amended and Restated Employment Agreement, dated as of January 1, 2023, between Oglethorpe and William F. Ussery.
10.16(3)	–	Employment Agreement, dated as of January 1, 2023, between Oglethorpe and David W. Sorrick.
10.17(3)	–	Second Amended and Restated Employment Agreement, dated as of January 1, 2023, between Oglethorpe and Annalisa M. Bloodworth.
14.1	–	Code of Conduct, available on our website, www.opc.com.
31.1	–	Rule 13a-14(a)/15d-14(a) Certification, by Michael L. Smith (Principal Executive Officer).
31.2	–	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).
32.1	–	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Michael L. Smith (Principal Executive Officer).
32.2	–	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).
*99.1	–	Member Financial and Statistical Information. (Filed as Exhibit 99.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2022, File No. 333-192954.)
101	–	XBRL Interactive Data File.

(1) Pursuant to 17 C.F.R. 229.601(b)(4)(iii), this document(s) is not filed herewith; however the registrant hereby agrees that such document(s) will be provided to the Commission upon request.

(2) Confidential treatment has been requested for certain confidential portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934. In accordance with Rule 24b-2, these confidential portions have been omitted from this exhibit and filed separately with the SEC.

(3) Indicates a management contract or compensatory arrangement required to be filed as an exhibit to this Report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of March, 2023.

OGLETHORPE POWER CORPORATION
(AN ELECTRIC MEMBERSHIP CORPORATION)

By: /s/ MICHAEL L. SMITH
MICHAEL L. SMITH
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ MICHAEL L. SMITH MICHAEL L. SMITH	President and Chief Executive Officer (Principal Executive Officer)	March 27, 2023
/s/ ELIZABETH B. HIGGINS ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 27, 2023
/s/ G. KENNETH WARREN, JR. G. KENNETH WARREN, JR.	Vice President, Controller (Principal Accounting Officer)	March 27, 2023
/s/ JIMMY G. BAILEY JIMMY G. BAILEY	Director	March 27, 2023
/s/ RANDY CRENSHAW RANDY CRENSHAW	Director	March 27, 2023
/s/ WM. RONALD DUFFEY WM. RONALD DUFFEY	Director	March 27, 2023
/s/ ERNEST A. JAKINS III ERNEST A. JAKINS III	Director	March 27, 2023
/s/ FRED MCWHORTER FRED MCWHORTER	Director	March 27, 2023

Signature	Title	Date
/s/ MARSHALL S. MILLWOOD MARSHALL S. MILLWOOD	Director	March 27, 2023
/s/ JEFFREY W. MURPHY JEFFREY W. MURPHY	Director	March 27, 2023
/s/ DANNY L. NICHOLS DANNY L. NICHOLS	Director	March 27, 2023
/s/ SAMMY G. SIMONTON SAMMY G. SIMONTON	Director	March 27, 2023
/s/ HORACE H. WEATHERSBY III HORACE H. WEATHERSBY III	Director	March 27, 2023
/s/ GEORGE L. WEAVER GEORGE L. WEAVER	Director	March 27, 2023
/s/ JAMES I. WHITE JAMES I. WHITE	Director	March 27, 2023