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, 2012

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. 000-53908

OglethorpePowerCorporation

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

Georgia (State or other jurisdiction of incorporation or organization)	**58-1211925** (I.R.S. employer identification no.)
2100 East Exchange Place **Tucker, Georgia** (Address of principal executive offices)	**30084-5336** (Zip Code)
Registrant's telephone number, including area code:	**(770) 270-7600**
Securities registered pursuant to Section 12(b) of the Act:	**None**
Securities registered pursuant to Section 12(g) of the Act:	**Series 2009 B Bonds**

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 electronically and posted on its corporate Web site, if any, 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [✓]

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

Large accelerated filer ____	Accelerated filer ____	Non-accelerated filer ✓ (Do not check if a smaller reporting company)	Smaller reporting company ____

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

2012 FORM 10-K ANNUAL REPORT

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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 the timing of various regulatory and other actions, future capital expenditures, business strategy 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 on Form 10-K. 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 construction projects, including the construction of two additional nuclear units at Plant Vogtle;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- potential legislative and regulatory responses to climate change initiatives, including the regulation of carbon dioxide and other greenhouse gas emissions;
- increasing debt caused by significant capital expenditures which is weakening certain of our financial metrics;
- commercial banking and financial market conditions;
- 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;
- uncertainty as to the continued availability of funding from the Rural Utilities Service and the availability of funding from the U.S. Department of Energy and other government sources;
- actions by credit rating agencies;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;
- adequate funding of our nuclear decommissioning trust fund including investment performance and projected decommissioning costs;
- weather conditions and other natural phenomena;
- 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;

- acts of sabotage, wars or terrorist activities, including cyber attacks;
- the credit quality and/or inability of various counterparties to meet their financial obligations to us, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- changes in technology available to and utilized by us or our competitors;
- general economic conditions;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption, energy conservation efforts and the general economy;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- litigation or legal and administrative proceedings and settlements;
- significant changes in critical accounting policies material to us; and
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards.

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 the largest electric cooperative in the United States in terms of 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 261 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 1.8 million electric consumers (meters) representing approximately 4.1 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 the majority of their aggregate power requirements primarily from our generation assets but also with power purchased from other power suppliers. We provide substantially all of 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."

We have interests in 31 operating generating units, fueled by nuclear, coal, gas, oil and water. See "OUR POWER SUPPLY RESOURCES" and "PROPERTIES – Generating Facilities."

In 2012, two of our members, Cobb EMC and Jackson EMC, accounted for 12.8% and 11.9% of our total revenues, respectively. Each of our other members accounted for less than 10% of our total revenues in 2012.

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 plant has been sold 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 any 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. For resources so approved in which less than all members participate, costs are shared first among the participating members, and if all 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. In 2012, we supplied energy that accounted for approximately 57% of the retail energy requirements of our members. 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 at intervals that we deem appropriate 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.

Our principal financial requirements are contained in the Indenture, dated as of March 1, 1997, from us to U.S. Bank National Association, as trustee (successor to SunTrust Bank), as amended and supplemented, referred to herein as the first mortgage indenture. 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. Margins for interest ratio is the ratio of margins for interest to total interest charges for a given period. Margins for interest is the sum of:

- our net margins (which includes our revenues subject to refund at a later date but excludes provisions for (i) non-recurring charges to income, including the non-recoverability of assets or expenses, except to the extent we determine to recover these charges in rates, and (ii) refunds of revenues we collected or accrued subject to refund), plus
- interest charges, whether capitalized or expensed, on all indebtedness secured under the first mortgage indenture or by a lien equal or prior to the lien of the first mortgage indenture, including amortization of debt discount or premium on issuance, plus
- any amount included in net margins for accruals for federal or state income taxes imposed on income after deduction of interest expense.

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.

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 – *Rates and Regulation.*"

The rate schedule formula also includes a prior period adjustment mechanism designed to ensure that we achieve the minimum 1.10 margins for interest ratio. Amounts, if any, by which we fall short of the minimum 1.10 margins for interest ratio are accrued as of December 31 of the applicable year and collected from our members from April through December of the following year. The rate schedule formula 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.

Under the first mortgage indenture and related loan contract with the Rural Utilities Service, adjustments to our rates to reflect changes in our budgets are generally not subject to Rural Utilities Service approval. Changes to the rate schedule under the wholesale power contracts are generally subject to Rural Utilities Service approval. Our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

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 capacity of 709 megawatts. We provide operations, financial and management services for Smarr EMC. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

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 37 of 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 accounting, auditing, communications, human resources, facility management, telecommunications and information technology at cost.

As of December 31, 2012, we had approximately $7.9 million of loans outstanding to Georgia System Operations, primarily for the purpose of financing capital expenditures. Georgia System Operations has an additional $8.0 million that can be drawn 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 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, the availability and magnitude of Rural Utilities Service-direct and guaranteed loan funds are subject to annual federal budget appropriations and thus cannot be assured. Currently, Rural Utilities Service-direct and guaranteed loan funds are subject to increased uncertainty because of budgetary and political pressures faced by Congress. The President's budget proposal for fiscal year 2013 provides for $6.1 billion in loans – a reduction of less than 10% from 2012 levels. Not more than $2 billion could be made available for environmental improvements to fossil-fueled generation that would reduce emissions, with the remaining funding limited to renewable energy, transmission, distribution and carbon-capture projects on generation facilities, and low emission peaking units affiliated with energy facilities that produce electricity from solar, wind and other intermittent sources of energy. However, Congress has not adopted a budget for 2013, but instead has adopted continuing resolutions including these restrictions with loan levels sufficient to meet the current demand. The President has not proposed a budget for fiscal year 2014. Although Congress has historically rejected proposals to dramatically curtail the Rural Utilities Service loan program, there can be no assurance that it will continue to do so. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service-direct and guaranteed loans that may be available to us in the future.

We have a loan contract with the Rural Utilities Service in connection with the first mortgage indenture. Under the loan contract, the Rural Utilities Service has approval rights over certain significant actions and arrangements, 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 rate schedule contained in the wholesale power contracts,
- changes to plant ownership and operating agreements,
- amounts of short-term debt outstanding exceeding 30% of our total utility plant through December 31, 2014 and 15% of total capitalization thereafter, and
- in limited circumstances, issuance of additional secured and unsecured debt.

The first mortgage indenture constitutes a lien on substantially all of the tangible and certain intangible property we own.

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 development and construction of Vogtle Units No. 3 and No. 4. 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. For further information regarding the agreements between Georgia Power and us and our members' relationships with Georgia Power, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Service Area and Competition" and "PROPERTIES – Fuel Supply," "– Co-Owners of Plants – *Georgia Power Company*" and "– The Plant Agreements."

Competition

Under current Georgia law, our members generally have the exclusive right to provide retail electric service in their respective territories. Since 1973, however, the Georgia Territorial Act has permitted 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. While the competition for 900-kilowatt loads represents only limited competition in Georgia, this 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 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.

We routinely consider, along with our members, a wide array of other potential actions to meet future power supply needs, to reduce costs, to reduce risks of the competitive generation business and to respond to competition. Alternatives that could be considered include:

- power marketing arrangements or other alliance arrangements;

- adjusting the mix of ownership and purchase arrangements used to meet power supply requirements;
- construction or acquisition of power supply resources, whether owned by us or by other entities;
- use of power purchase contracts to meet power supply requirements, and whether to use short, medium or long-term contracts, or a mix of terms;
- participation in future power supply resources developed by others, whether by ownership or long-term purchase commitment;
- whether disposition of existing assets or asset classes would be advisable;
- maturity extensions of existing indebtedness;
- potential prepayment of debt;
- various responses to the proliferation of non-core services offered by electric utilities;
- mergers or other combinations among distributors or power suppliers; and
- other regulatory and business changes that may affect relative values of generation classes or have impacts on the electric industry.

We will continue to consider industry trends and developments, but cannot predict the outcome or any action we or our members might take based on these industry trends and developments. These considerations necessarily would take account of and are subject to legal, regulatory and contractual considerations.

Regulation of greenhouse gas emissions has the potential to affect energy suppliers, including us and our competitors, differently, depending not only on the relative greenhouse gas emissions from a supplier's sources, but also on the nature of the regulation. For example, certain legislative proposals have included various credits that would ultimately be phased out to offset the initial economic impact of regulation. Our greenhouse gas emissions are significant, but we also have generation sources that emit no greenhouse gases. Some of our competitors use sources that emit proportionately more greenhouse gases, while the sources of some competitors emit less. Further, third-party suppliers to our members 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 our members would be affected by regulation of the greenhouse gas emissions of these suppliers. We believe our and our members' diverse portfolios of generation facilities, including the diversity of third-party suppliers, along with potential credits that could be available to us or our members under certain legislative proposals, would mitigate the impact, if any, on our and our members' competitiveness resulting from these legislative proposals, if enacted. See "REGULATION – Environmental – Carbon Dioxide Emission and Climate Change – *Pending Legislation*" and "RISK FACTORS."

Many members are also providing or considering proposals to provide non-traditional products and services such as natural gas, telecommunications 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.

Depending on the nature of the generation business in Georgia, there could be reasons for the members to separate their physical distribution business from their energy business, or otherwise restructure their current businesses to operate more effectively.

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, our peak sales have occurred during the months of June through August. Even so, summer sales historically have been lower when weather conditions are milder and higher when weather conditions are more extreme. 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 can not 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 reflect the recovery of our fixed costs, which do not vary significantly from month to month; therefore, capacity charges are billed and capacity revenues are recognized in substantially equal monthly amounts.

OUR POWER SUPPLY RESOURCES

General

We supply capacity and energy to our members for a portion of their requirements from a combination of our generating assets and power purchased from other suppliers. In 2012, we supplied approximately 57% of the retail energy requirements of our members.

Generating Plants

We have interests in 31 operating generating units. The Municipal Electric Authority of Georgia, the City of Dalton and Georgia Power also have interests in nine of these units – at Plants Hatch, Vogtle, Wansley and Scherer. Georgia Power serves as operating agent for these units. Georgia Power also has an interest in Rocky Mountain, which we operate.

See "PROPERTIES" for a description of our generating facilities, fuel supply and the co-ownership arrangements and Note 6 to Notes to Consolidated Financial Statements regarding the power purchase agreement with Doyle I, LLC that we account for as a capital lease. Also see "PROPERTIES – The Plant Agreements – *Doyle.*"

Power Purchase and Sale Arrangements

Power Purchases

We currently have no material power purchase agreements. We purchase small amounts of capacity and energy from "qualifying facilities" under the Public Utility Regulatory Policies Act of 1978. Under a waiver order from the Federal Energy Regulatory Commission, we historically made all purchases the members would have otherwise been required to make under the Public Utility Regulatory Policies Act and we were relieved of our obligation to sell certain services to "qualifying facilities" so long as the members make those sales. In 2012, our purchases from such qualifying facilities provided less than 0.1% of the energy we supplied to our members. Under their wholesale power contracts, the members may now make such purchases instead of us.

Power Sales

We sell energy generated at the Thomas A. Smith Energy Facility, formerly known as the Murray Energy Facility, to third parties when profitable. We intend to continue marketing this generation to third parties prior to our members' use of the resource, planned for 2016.

Pursuant to a purchase and sale agreement acquired in connection with the Hawk Road Energy Facility, we sell 500 megawatts of capacity and associated energy from Hawk Road to seven of our members through December 31, 2015. After the expiration of this agreement, Hawk Road will be available to all of the participating members.

Other Power System Arrangements

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.

Future Power Resources

Plant Vogtle Units No. 3 and No. 4

We are participating in 30% of the cost of constructing two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4.

In April 2008, Georgia Power, for itself and as agent for us, the Municipal Electric Authority of Georgia and the City of Dalton, the "Co-owners," signed an Engineering, Procurement and Construction Contract with Westinghouse Electric Company, LLC and Stone & Webster, Inc., together, the "Contractor." Pursuant to the contract, the Contractor will supply and construct two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology, with the exception of certain owner supplied items. Under the contract, the Co-owners will pay a purchase price that is subject to certain price escalation and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders and performance bonuses. Each Co-owner is severally, not jointly, liable to the Contractor based on its ownership share. The contract includes certain liquidated damages upon the Contractor's failure to comply with schedule and performance guarantees. The Contractor's liability for those liquidated damages and for warranty claims is subject to a cap.

The obligations of Westinghouse and Stone & Webster are guaranteed by their parent companies Toshiba Corporation and The Shaw Group, Inc., a subsidiary of Chicago Bridge & Iron Co. N.V., respectively. In the event of certain credit rating downgrades of any Co-owner, that Co-owner would be required to provide a letter of credit or other credit enhancement to the Contractor. In addition, the Co-owners may terminate the contract at any time for their convenience, provided that the Co-owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may terminate the contract under certain circumstances, including certain Co-owner suspension or delays of work, action by a governmental authority to stop work permanently, certain breaches of the contract by the Co-owners, Co-owner insolvency and certain other events. As agent for the Co-owners, Georgia Power has designated Southern Nuclear Operating Company as its agent for contract management.

The Nuclear Regulatory Commission certified the Westinghouse AP1000 Design Control Document (DCD) effective December 30, 2011. On February 10, 2012, the Nuclear Regulatory Commission issued combined licenses for Vogtle Units No. 3 and No. 4 which allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the Nuclear Regulatory Commission's issuance of the combined licenses and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the combined licenses with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the combined licenses. Georgia Power, on behalf of the Co-owners, has intervened in and intends to vigorously contest these petitions. Additional technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4, at the federal and the state level, are expected as construction proceeds.

The Co-owners and the Contractor have established both informal and formal dispute resolution procedures in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, has successfully initiated both formal and informal claims through these procedures, including ongoing claims. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and the Co-owners are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

The most significant litigation relates to costs associated with design changes to the DCD and costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the combined construction permits and operating licenses by the Nuclear Regulatory Commission. In July 2012, the Co-owners and Contractor began negotiations regarding these costs, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the contract. The Contractor has claimed that its estimated adjustment attributable to us, based on our ownership interest, is approximately $280 million in 2008 dollars with respect to these issues. The Contractor has also asserted that it is entitled to schedule extensions. Georgia Power, on behalf of the Co-owners, has not agreed with either the proposed cost or schedule adjustments or that the Co-owners have any responsibility for costs related to these issues. On November 1, 2012, the Co-owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia, seeking a declaratory judgment that the Co-owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Co-owners in the U.S. District Court for the District of Columbia alleging the Co-owners are responsible for these costs. Georgia Power and the Co-owners intend to vigorously defend their positions. During litigation, Georgia Power and the Co-owners expect negotiations with the Contractor to continue with respect to cost and schedule during which time the parties will attempt to reach a mutually acceptable compromise of their positions.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the combined licenses, including rigorous inspection by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction. In late 2012, certain details of the rebar design for the Vogtle Unit No. 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. The Nuclear Regulatory Commission has approved two license amendment requests submitted by Southern Nuclear to conform the rebar design details to applicable requirements and pouring of the base mat concrete has been completed, allowing construction of the nuclear island to continue. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any future license amendment requests 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 Contractor, or both.

The issues mentioned above, in addition to other factors that have materialized during the development and construction process, have caused revisions to the estimated project schedule and cost. Georgia Power has revised the estimated commercial operation dates for Units No. 3 and No. 4 from April of 2016 and 2017, respectively, to the fourth quarter of 2017 and 2018, respectively. Additionally, our estimated cost for the new units, including allowance for funds used during construction and a contingency amount, is approximately $4.5 billion, an increase from our original $4.2 billion estimate.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards or other issues, including the litigation discussed above, may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the contract, but also may be resolved through litigation.

As of December 31, 2012, our share of capitalized costs for this project was approximately $1.7 billion. We have issued approximately $1.4 billion of first mortgage bonds through the capital markets to provide long-term financing for a portion of these costs. We and the Department of Energy have executed a conditional term sheet for up to $3.057 billion of our project costs. However, issuance of the loan is subject to negotiation and acceptance of final terms and conditions and cannot be assured. We expect that we will finance additional project costs in the capital markets, including any amounts not funded through the Department of Energy loan program. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Capital Requirements – Capital Expenditures*" and "*– Financing Activities.*"

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 and operation of nuclear generating units.

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."

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 1.8 million electric consumers (meters) representing approximately 4.1 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 with one of our quarterly reports on Form 10-Q an exhibit containing financial and statistical information for our 38 members for the most recent three year period.

In March 2013, Pataula EMC completed its consolidation with Cobb EMC, including transfer of its membership in us to Cobb. Cobb acquired Pataula in 2005 and has been serving Pataula's former members since then. The completion of this consolidation will have no effect on our financial condition, results of operations or cash flow.

The following table shows the aggregate peak demand and energy requirements of our members for the years 2010 through 2012, and also shows the amount of their energy requirements that we supplied. From 2010 through 2012, demand requirements of the members increased at an average annual compound rate of 2.0% and energy requirements decreased at an average annual compound rate of 4.7%.

	Member Demand (MW)	Member Energy Requirements (MWh)	
	Total(1)	Total(2)	Supplied by Oglethorpe(3)
2010	8,990	40,169,810	22,644,790
2011	8,998	38,000,846	19,574,145
2012	9,353	36,491,624	20,852,826

(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.

(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."

(3) Includes energy supplied to members for resale at wholesale. We supplied none of Flint's energy requirements during this period and do not currently anticipate supplying any until 2016.

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 premise and the electric utility is unwilling or unable to comply with an order from the Georgia Public Service Commission regarding the service.

Since 1973, the Georgia Territorial Act has allowed 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. While the competition for 900-kilowatt loads represents only limited competition in Georgia, this 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%. 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 the 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, 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 that a member which is not an 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, the availability and magnitude of Rural Utilities Service direct and guaranteed loan funds is subject to annual federal budget appropriations and thus cannot be assured. Currently, the availability of Rural Utilities Service loan funds is subject to increased uncertainty because of budgetary pressures faced by Congress.

The President's budget proposal for fiscal year 2013 proposed to reduce funding by less than 10% from 2012 levels for the Rural Utilities Service electric program. The proposed funding would be available only for transmission, distribution, renewable energy and carbon capture projects for generation and certain environmental improvements. However, Congress has not adopted a budget for 2013, but instead has adopted continuing resolutions including these restrictions with loan levels sufficient to meet the current demand. The President has not proposed a budget for fiscal year 2014. We cannot predict the amount or cost of Rural Utilities Service direct and guaranteed loans that may be available to the members in the future.

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 could otherwise occur. 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 2012, we supplied approximately 57% of the retail energy requirements of our members. Pursuant to the wholesale power contracts, we supply each member, other than Flint, 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." Additionally, effective May 2009, we assumed a power purchase and sale agreement with seven of our members in connection with our acquisition of Hawk Road. See "OUR POWER SUPPLY RESOURCES – Power Purchase and Sale Arrangements – *Power Sales.*" Our members satisfied all of their requirements above their purchase obligations to us with purchases from other suppliers as described below.

Contracts with Southeastern Power Administration

Our members purchase hydroelectric power from the Southeastern Power Administration, or SEPA, under contracts that extend until 2016 and thereafter until terminated by two years' written notice by SEPA or the respective member. In 2012, the aggregate SEPA allocation to the members was 618 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, 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 Corps of Engineers projects from which its allocation is derived in order to retain the allocation.

Smarr EMC

The 35 members participating in the facilities owned by Smarr EMC purchase the output of those facilities pursuant to long-term, take-or-pay power purchase agreements. Smarr EMC owns Smarr Energy Facility, a two-unit, 217 megawatt gas-fired combustion turbine facility, and Sewell Creek Energy Facility, a four-unit, 492 megawatt gas-fired combustion turbine facility. Smarr Energy Facility began commercial operation in June 1999, and Sewell Creek Energy Facility began commercial operation in June 2000. See "OGLETHORPE POWER CORPORATION – Relationship with Smarr EMC."

Green Power EMC

Our members are also members of Green Power Electric Membership Corporation, a power supply cooperative specializing in the purchase of renewable energy sources for its members. The members purchase small quantities of energy from Green Power EMC. We supply management services to Green Power EMC.

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.

Georgia Power Block Purchase

Thirty members have entered into power supply contracts with Georgia Power under which they purchase an aggregate of 750 megawatts of capacity and associated energy. These contracts expire December 31, 2014.

Other Member Resources

Our members obtain their remaining power supply requirements from various sources. Thirty-three members have entered into contracts with third parties for some or all of their incremental power requirements, with remaining terms ranging from 3 to 33 years. The other members use a portfolio of power purchase contracts to meet their requirements.

We have not undertaken to obtain a complete 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 is typical for electric utilities, we are subject to various federal, state and local environmental laws that apply to our operations. 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.

In general, these and other types of environmental requirements are becoming increasingly stringent. Although we have installed or are in the process of installing environmental control systems at our plants to ensure continued compliance with existing requirements, including systems to reduce emissions of sulfur dioxide, oxides of nitrogen, mercury and other pollutants at Plants Scherer and Wansley, new requirements could be imposed. Such requirements may substantially increase the cost of electric service, by requiring modifications in the design or operation of existing facilities, the purchase of emission allowances, or changes or delays in the location, design, construction or operation of new facilities. 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 or future environmental laws or regulations. Should we fail to be in compliance with these requirements, it would constitute a default under those debt instruments. Although it is our intent to comply with current and future regulations, we cannot provide assurance that we will always be in compliance.

Our capital expenditures and operating costs continue to reflect expenses necessary to comply with environmental standards. 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 concerns of the public, the scientific community and Congress have resulted in the enactment of legislation that has had and will continue to have a significant impact on the electric utility industry. The most significant environmental legislation applicable to us is the Clean Air Act, which regulates emissions of sulfur dioxide, nitrogen oxides, particulate matter, greenhouse gases and other pollutants from affected electric utility units, including the coal-fired units at Plants Scherer and Wansley. The following appear to be the most significant ongoing Clean Air Act related actions.

National Ambient Air Quality Standards and Nonattainment Updates. The Clean Air Act requires the Environmental Protection Agency, or EPA, to set National Ambient Air Quality Standards (NAAQS) for six common air pollutants, five of which are of principal importance to utilities – particulate matter, ground-level ozone, carbon monoxide, sulfur dioxide and nitrogen dioxide – and, of less significance to utilities, lead. Many of the NAAQS have recently been revised or are in the process of being revised to make them more stringent. Typically, once finalized, revised standards are litigated. More stringent NAAQS could cause certain areas in Georgia to be reclassified as ''nonattainment,'' which may require additional emissions reductions from certain power plants we own or co-own to bring those areas into ''attainment.'' Although our coal-fired plants already have control systems for these pollutants installed or being installed, the implementation of new or revised NAAQS could lead to compliance challenges. The costs of any additional pollution control equipment that could be required due to new or revised NAAQS cannot be determined at this time.

Clean Air Interstate Rule and the Cross State Air Pollution Rule. EPA finalized the Clean Air Interstate Rule (CAIR) in 2005 for ozone and fine particulate matter, requiring emissions reductions in sulfur dioxide and nitrogen oxides in most eastern states, including Georgia, through a market-based cap and trade program. In August 2011, EPA finalized the Cross State Air Pollution Rule (CSAPR) to replace the CAIR. Similar to the CAIR, the CSAPR was to impose cap and trade programs for sulfur dioxide and nitrogen oxides emissions on fossil fuel-fired electric generating units located in covered states, including Georgia. However, in August of 2012, the U.S. Court of Appeals for the

D.C. Circuit vacated the CSAPR, remanding it back to EPA for further consideration and, in light of the decision, the Court ordered that the CAIR remain in place. Whether that decision will be appealed to the U.S. Supreme Court is not known. While the outcome of these CSAPR proceedings may affect the future operations of our co-owned units at Plants Scherer and Wansley, given that additional emission control systems will be coming on line beginning in 2013 at Plant Scherer, we do not expect that allowance purchases or operating limitations will be necessary.

Mercury and Air Toxics Standards and State Mercury Rule. In December 2011, EPA finalized its Mercury and Air Toxics Standards (MATS) rule which established maximum achievable control technology limits for certain hazardous air pollutants at coal and oil-fired electric generating units. For coal units, the rule sets stringent emission limits to control various hazardous air pollutants such as mercury, non-mercury metals and acid gases and work practice standards to control organics and dioxins. Affected generating units will have until April 16, 2015 to comply; however, extensions for one or two years are possible under limited circumstances. Challenges to the MATS have been filed.

Georgia's current mercury rules include a "multi-pollutant rule" that requires operation of existing controls at Plant Wansley, which includes selective catalytic reduction systems and scrubbers. To comply with MATS at Plant Wansley, we expect injection of activated carbon and other chemicals will be needed. Modifications related to activated carbon injection at Plant Wansley are expected to be completed by 2014. At Plant Scherer, Georgia's "multi-pollutant rule" requires operation of existing and planned controls, which includes activated carbon injection equipment and baghouses already completed, and selective catalytic reduction systems and scrubbers that are currently under construction, which we expect will be completed by 2014. Once completed, our total investment in all of these projects is estimated to be approximately $1.2 billion, including allowance for funds used during construction.

Startup, Shut-down or Malfunction. On February 12, 2013, EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). EPA proposes a determination that the SSM provisions in the SIPs for 36 states, including Georgia, do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

New Source Review. In November 1999, the United States Department of Justice, on behalf of EPA, filed lawsuits against Georgia Power and some of its affiliates, as well as other utilities. The lawsuits allege violations of the new source review provisions and the new source performance standards of the Clean Air Act at Plant Scherer Unit Nos. 3 and 4 as well as other facilities. We are not currently named in the lawsuits and we do not have an ownership interest in the named Plant Scherer units. However, we can give no assurance that units in which we have an interest will not be affected by this or a related lawsuit in the future. The case has remained administratively closed since the spring of 2001. The resolution of this matter is highly uncertain at this time, as is any responsibility for a share of any penalties and capital costs that might be required to remedy violations at the co-owned facilities.

Rulemakings that began in 2009 now impose new source review requirements on greenhouse gases, including carbon dioxide, under the Prevention of Significant Deterioration (PSD) preconstruction permitting program. The PSD preconstruction permitting program affects new generation resources as well as certain major modifications to existing resources. As a result, PSD review for major stationary sources of greenhouse gases was triggered on January 2, 2011. See "Carbon Dioxide Emissions and Climate Change – *Executive Branch Action*."

Air Quality Summary. We believe that the controls being designed and/or installed at Plants Scherer and Wansley will meet the requirements of the rules described above. However, depending on the final outcome of these or other rules relating to air quality, and the implementation approach selected by EPA and the State of Georgia with respect to environmental regulations, we may have to incur significant capital expenditures and increased operating expenses at certain of our generating facilities, particularly Plants Scherer and Wansley.

Compliance with the requirements of the Clean Air Act may also require increased capital or operating expenses on the part of Georgia Power. Any increases in Georgia Power's capital or operating expenses may cause an increase in the cost of power purchased from Georgia Power. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Georgia Power Block Purchase.*"

Carbon Dioxide Emissions and Climate Change

Efforts to limit emissions of carbon dioxide from power plants continue. Such limitations on emissions could originate in the Congress, the executive branch or the courts.

Emissions of carbon dioxide from our plants totaled approximately 12.4 million short tons in 2012. In 2012, 30.5% of our generation, excluding pumped storage, came from our interests in the coal-fired units at Plants Scherer and Wansley, which would be the most impacted by any greenhouse gas-related legislation or regulation, while another 29.2% came from our gas-fired facilities which would also be somewhat impacted but not to the same extent as the coal-fired plants. The remaining generation (40.3%) came from our interest in the nuclear Plants Vogtle and Hatch which would likely not be impacted by any climate change legislation or regulation aimed at reducing greenhouse gas emissions.

Pending Legislation. At this time, we do not anticipate that the 113th Congress will pass any legislation directly regulating greenhouse gases, including carbon dioxide. We also do not anticipate the passage of any indirect standard for carbon dioxide, such as a national renewable or clean energy electricity standard. However, we cannot be certain whether any legislation will be passed by this or a future Congress that would directly or indirectly regulate greenhouse gas emissions from our power plants, nor can we predict the impacts from any such legislation.

Executive Branch Action. President Obama has highlighted reducing greenhouse gas emissions as one of the priorities for his second term and any changes in requirements will most likely be the result of executive branch actions. The U.S. Supreme Court ruled in 2007 that certain greenhouse gases, including carbon dioxide, are pollutants which EPA has the authority to regulate under the Clean Air Act if EPA concludes regulation is needed to protect public health or welfare. EPA determined that regulation was needed and issued a series of rules that establish a three-step schedule for application of the Clean Air Act PSD and Title V programs to stationary source emissions of greenhouse gases. The first two steps of regulation began on January 2, 2011 and July 1, 2011 for larger sources of greenhouse gases. EPA's third step, issued on July 12, 2012, maintains the current permitting thresholds. In addition, EPA proposed in April 2012 a revised New Source Performance Standard (NSPS) for new steam generating units operated by electric utilities that limits greenhouse gas emissions and that NSPS is expected to be finalized by May 2013. Once EPA promulgates a NSPS for a category of new, modified or reconstructed emissions sources, it is required to establish guidelines requiring states to develop emission standards for this same category of existing sources. Thus, greenhouse gas NSPS for existing sources may be issued at some point in the future. The final rules discussed above will be appealed to the U.S. Supreme Court, and challenges to future rules may be brought if and when such rules are finalized. We cannot predict at this time how further developments may affect the regulation of greenhouse gas emissions from our power plants, including capital requirements.

Litigation. While litigation related to carbon dioxide emissions continues on numerous fronts, we cannot predict the outcome of such litigation, or the effect it could have on any of the power plants that we own.

Climate Change Summary. While the outcome of these matters cannot be determined at this time, adverse results in one or more of the above-described matters could result in substantial capital expenditures and/or increased operating costs at our fossil-fuel fired power plants, especially Plants Scherer and Wansley.

Coal Combustion Residuals

In May 2010, EPA proposed two alternative approaches for regulating coal combustion residuals from electric utilities: regulation as listed "special wastes" under hazardous wastes rules or as solid waste. Although EPA proposes to exempt the beneficial use of coal combustion residuals, a designation as hazardous waste may limit or eliminate beneficial reuse options. Adoption of either approach may require closure of or significant changes to existing storage units, extended plant outages, construction of lined landfills and groundwater monitoring facilities, and additional material management and financial assurance requirements. A variation of the second approach might not require early closure of existing wet storage facilities. After the proposal, EPA issued two notices of data availability, seeking comment on the validity and propriety of the use of certain information listed in the notices or rulemaking docket to make regulatory decisions about coal combustion residuals. Indications are that EPA will take further action on this rule in 2013 or 2014. Depending upon which method of regulation EPA selects, if any, preliminary estimates by many utilities and industry groups suggest that compliance costs are greater than originally anticipated by EPA and could be significant; however, any compliance costs will depend on the final form of the rules adopted. Preliminary estimates suggest that our compliance costs could be approximately one half a billion dollars or potentially more and occur in the 2016 to 2020 period. Estimated costs are based on pre-screening figures that should be distinguished from the more formalized cost estimates provided for projects that are more definite as to scope and timing and the ultimate impacts associated with either proposal cannot be determined with certainty at this time.

Water Use and Wastewater Issues

Since 2005, EPA has been reviewing wastewater discharges from coal-fired power plants to determine whether new Steam Electric Power Generating effluent guidelines that cover wastewater discharge standards under the Clean Water Act are needed. EPA has entered into a consent decree that requires it to propose regulations by April 2013 and to finalize such proposal by May 2014. While the updated regulations are expected to address wastewater pollutants arising from the operation of ash ponds and flue gas desulfurization units at coal-fired power plants, the impacts of such guidelines cannot be determined at this time and will depend on the development of future implementing regulations.

In February 2008, the Georgia legislature adopted a comprehensive State Water Plan that lays out statewide policies, management practices and guidance for regional water planning in Georgia. In November 2011, the Georgia Environmental Protection Division adopted regional water plans that were developed pursuant to the State Water Plan. Regional plans include resource assessments, estimates of current and future water needs and management practices. Pursuant to the State Water Plan, Georgia will consider the information contained in regional water plans when making water use permitting decisions under existing state law. Regional water plans will be reviewed periodically and may be revised in the future. In addition, the state water planning process may lead to new or revised regulations for water users in the future. Because power generation is a key use of water in Georgia, the regional water plans and any future regulations or other enforceable requirements developed in connection with the State Water Plan may have substantial effects on the operations of our facilities or future facilities that we construct or acquire. The impacts of future regulations or revisions to regional water plans on our facilities or future facilities cannot be determined at this time.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. In April 2011, EPA proposed new national requirements under section 316(b) to reduce the impact on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. Applying to existing power generating facilities withdrawing more than two million gallons per day from waters of the United States and using at least 25% of the water exclusively for cooling, the proposal primarily requires utilities to add cooling towers on power plants that currently utilize "once through" cooling systems. The proposed regulations would apply to Plants Hatch, Vogtle, Scherer and Wansley; however, each of these plants already has operational cooling towers and any effects of the rule are not expected to be significant. EPA is under court order to issue a final rule by June 2013 and any effect on these plants will depend on the content of the final rule and the results of any ensuing legal challenges.

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 to the regulations implementing these statutes. We do not believe that compliance with these statutes and regulations will have a material impact on our financial condition or results of operations. 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. 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.

For example, in January 2013, several plaintiffs filed complaints against us and the other co-owners of Plant Scherer claiming personal injury and property damage arising from the alleged release of hazardous substances from the plant, primarily related to the coal-ash pond, into the surrounding groundwater and air. We and the other co-owners intend to vigorously defend these claims. We do not believe this litigation will have a material adverse effect on our results of operations or financial condition; however, the ultimate outcome of this litigation 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*."

On March 11, 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the Nuclear Regulatory Commission is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On July 12, 2011, a special Nuclear Regulatory Commission task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S. On March 12, 2012, the Nuclear Regulatory Commission issued three orders and a request for information based on the task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the Nuclear Regulatory Commission staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the Nuclear Regulatory Commission's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain Nuclear Regulatory Commission approval for taking an approach other than as outlined in the interim staff guidance. Preliminary estimates indicate that our increased capital and operational costs as a result of the three orders and request for information will be approximately \$20 to \$30 million through 2017. However, the final form and impact of additional Fukushima related changes to safety requirements for nuclear reactors will be dependent on further review and action by the Nuclear Regulatory Commission. See "RISK FACTORS" for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

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. These contracts require each such owner to pay a fee, which is currently just under one dollar per megawatt-hour for the net electricity generated and sold by each of its reactors.

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. Based on our ownership interests, we received $16.2 million in 2012 as a result of the settlement of the first lawsuit seeking damages for certain nuclear fuel spent fuel costs. See Note 1 of Notes to Consolidated Financial Statements for information regarding the status of this litigation.

Plants Hatch and Vogtle currently have on-site spent-fuel wet storage capacity and Plant Hatch has an on-site dry storage facility. The on-site dry storage facility for Plant Hatch became operational in 2000 and can be expanded to accommodate spent fuel through the life of the plant. Plant Vogtle's spent fuel pool storage is expected to be sufficient until 2014. Construction of on-site dry storage capacity at Plant Vogtle has commenced to ensure that we maintain full-core discharge capability to the spent fuel pool. See Note 1 of Notes to Consolidated Financial Statements.

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 is 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 2027. See "PROPERTIES – Generating Facilities" for additional information.

Upon or after the expiration of the 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 original licensee or to a new licensee. In the event of takeover or relicensing to another, the original 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. 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, generator operator and participant in wholesale power transactions, 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 make annual self-certifications of compliance with specific requirements. SERC Reliability Corporation also conducts regular audits of 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 the most significant 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 significant, could negatively affect our business operations, financial condition and future results of operations.

We are exposed to continued cost uncertainty in connection with the construction of two additional nuclear units at Plant Vogtle.

We have committed significant capital expenditures to participate in the construction of two additional nuclear units at Plant Vogtle. The construction of large, complex generating plants involves significant financial risk. Further, no nuclear plants have been constructed in the United States using advanced designs, such as the Westinghouse AP1000, and therefore estimating the total cost of construction and the related schedule is inherently uncertain. We also rely on our agents for the construction of the additional units at Plant Vogtle and do not exercise direct control over the construction process.

Factors that have either affected construction to date or that could lead to further cost increases and schedule delays or even the inability to complete this project include:

- performance by the Contractor, including compliance with the design specifications approved and quality standards set forth by the Nuclear Regulatory Commission;
- contract disputes;
- shortages and/or inconsistent quality of equipment, materials and labor;
- unforeseen engineering problems;
- changes in project design or scope;
- work stoppages;
- permits, approvals and other regulatory matters;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- erosion of public and policymaker support;
- adverse weather conditions;
- environmental and geological conditions;
- unanticipated increases in the costs of materials and labor; and
- increases in our cost of debt financing.

During course of development and construction activities for Vogtle Units No. 3 and No. 4, issues such as certain of these factors have materialized and impacted original schedule and cost estimates. These issues have delayed the estimated commercial operation dates of the units from April 2016 and April 2017, respectively, to the fourth quarters of 2017 and 2018, respectively, and increased the estimated project cost from $4.2 billion to $4.5 billion. Separately, we and the other Co-owners are engaged in litigation with the Contractor for costs associated with delays related to the timing of the Nuclear Regulatory Commission issuing the necessary design and licensing approvals. The Contractor has asserted that, based on our ownership interest, we are responsible for an additional $280 million in 2008 dollars and that it is entitled to further contract extensions with respect to the licensing delays. In addition, there have been technical and procedural challenges to the construction and licensing of these units and similar additional challenges at the federal and the state level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time; however, these risks could continue to affect the in-service cost of 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.

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years. Future environmental laws and regulations, including laws and regulations designed to address climate change, air and water quality, coal combustion byproducts and other matters may increase our compliance costs or liabilities in the future.

As with most electric utilities, we are subject to extensive federal, state and local environmental requirements which regulate, among other things, air emissions, water discharges and use 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.

Generally, existing environmental regulations are becoming increasingly stringent, and we may also be subject to new legislation or regulation, including legislation or regulation relating to greenhouse gas emissions or renewable or clean energy standards. Through 2012, we have spent approximately $1.1 billion on capital expenditures for air pollution control projects to achieve and maintain compliance with applicable environmental regulations at our facilities, and we expect that we will spend an additional $120 million through 2014 in efforts to maintain compliance. More stringent standards may require us to modify the design or operation of existing facilities, purchase emission allowances or change the location, design, construction or operation of new facilities. These actions may result in substantial increases in the cost of electric service to our members.

For example, in 2010, EPA proposed two alternative approaches for regulating coal combustion byproducts from electric utilities as either ''special'' wastes under hazardous waste rules or as solid wastes. Although EPA proposes to exempt the beneficial use of coal combustion byproducts, a designation as hazardous waste may limit or eliminate beneficial reuse options. Further, adoption of either approach may require closure of or significant changes to existing storage units, extended plant outages, construction of lined landfills, groundwater monitoring facilities and additional material management and financial assurance requirements. Depending upon which method of regulation EPA selects, if any, and the final form of the rules adopted, preliminary estimates suggest that our compliance costs could be approximately one half a billion dollars or potentially more.

Additionally, efforts in the United States and internationally to limit emissions of greenhouse gases, in particular, carbon dioxide, from power plants continue. In fact, President Obama has highlighted reducing greenhouse gas emissions as one of the priorities for his second term. Although climate change legislation has not been adopted at the federal level, EPA continues to move forward with the regulation of greenhouse gas emissions under the Clean Air Act. EPA has determined that certain greenhouse gas emissions, including carbon dioxide, from new motor vehicles endanger public health or welfare, and it has implemented a program requiring the annual reporting of greenhouse gas emissions by many industries, including the electric utility industry. Effective January 2011, EPA determined that carbon dioxide and other greenhouse gases are regulated pollutants under the Prevention of Significant Deterioration preconstruction permit program and the Title V operating permit program under the Clean Air Act, which apply to power plants and other commercial and industrial facilities. As a result, the construction of new facilities or major modifications to existing facilities could trigger the need for certain permits and the application of the best available control technology for greenhouse gas emissions. In addition, EPA may propose New Source Performance Standard guidelines that would apply to existing coal-fired electric generating facilities, including Plants Scherer and Wansley; however, the timing of such guidelines is uncertain. Emissions of carbon dioxide from our plants totaled approximately 12.4 million short tons in 2012.

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.

Litigation relating to environmental issues, including claims of property damage or personal injury caused by greenhouse gas emissions or alleged exposure to hazardous materials, such as the current litigation against the co-owners of Plant Scherer, has increased generally throughout the U.S. Likewise, actions by private citizen groups to enforce environmental laws and regulations are increasingly prevalent. While management does not currently anticipate that such litigation would have a material adverse effect on our financial condition or future results of operations, the ultimate outcome of any of these actions cannot be predicted.

In addition, existing environmental laws and regulations may be revised or new laws and regulations seeking to protect public health and/or the environment may be adopted or become applicable to our facilities. Revised or additional laws and regulations, and in particular climate change regulations, could result in significant additional expense and operating restrictions on our facilities or increased compliance costs which 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 created and cannot be determined at this time.

Capital expenditures are projected to be significant and will continue to increase our debt.

In order to meet the future energy needs of our members, we are participating in the construction of Vogtle Units No. 3 and No. 4 and, over the past few years, have acquired over 2,000 megawatts of gas-fired generation. We expect our total investment in these projects to exceed $5 billion once the Vogtle expansion is completed. We are also making significant investments in connection with environmental control equipment being installed at our existing coal-fired facilities in order to comply with current environmental laws and regulations. As we have financed generation assets in the past, we are financing these new projects with debt. As of December 31, 2012, we had approximately $6.5 billion of debt outstanding. At the completion of the Vogtle expansion and the projected environmental retrofits on our coal-fired facilities, we expect that we will have approximately $9.4 billion of debt outstanding.

In addition to the increase in absolute dollars, our debt is increasing as a percentage of our total capitalization, which is weakening certain of our financial metrics. In order to increase financial coverage during this expansion period, beginning in 2009, our board of directors has approved budgets to achieve a greater margins for interest ratio 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 2013 our board of directors approved a margins for interest ratio of 1.14. However, even with increased margins, the amount of incremental debt associated with these capital investments will continue to decrease our equity ratio during this period of increased borrowing, which could impact our credit ratings. Any downgrade in our credit ratings could increase our borrowing costs and decrease our access to the credit and capital markets.

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 expenditure requirements 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. Historically, we and other electric generating cooperatives have 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. Although Congress has historically rejected proposals to curtail the Rural Utilities Service loan program, there can be no assurance that it will continue to do so. Because of these factors, we cannot predict the amount of Rural Utilities Service loans that may be available to us in the future. 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. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Relationship with Rural Utilities Service" and "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Sources of Capital and Liquidity – Sources of Capital*."

In connection with our share of the cost of constructing two additional nuclear units at Plant Vogtle, in May 2010 we signed a conditional term sheet that sets forth the general terms of a loan from the Federal Financing Bank and a related loan guarantee from the Department of Energy that would fund up to $3.057 billion of eligible project costs. However, final approval and issuance of a loan guarantee by the Department of Energy is subject to negotiation of definitive agreements, completion of due diligence by the Department of Energy and satisfaction of other conditions. In the event that the Department of Energy does not issue a loan guarantee to us or the Co-owners determine that the final terms and conditions are not in their best interests, we expect to continue to finance the construction of these units through the capital markets, which will likely be at a higher cost.

Therefore our access to both short-term and long-term capital market funding has become an increasingly important factor in our financing plans, particularly in light of the significant amount of projected capital investment. We have entered into multiple credit agreements to provide significant short-term and medium-term liquidity and 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 could 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 existing liquidity.

Our borrowing costs are also affected by prevailing interest rates. Although we have hedged a significant portion of our exposure to rising interest rates related to the construction of Vogtle Units No. 3 and No. 4, the hedges we have in place only cover a portion of our total exposure to increased interest rates. 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 to the extent these increases are not offset by any interest rate hedges and our financial condition and future results of operations could be adversely affected.

In addition, market disruptions could constrain, at least temporarily, lenders' 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:

- market conditions generally, such as the continued uncertainty in the credit and capital markets;
- economic downturns or recessions;
- 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;
- negative events in the energy industry, such as a bankruptcy of an unrelated energy company or the occurrence of a significant natural disaster;
- lender concerns regarding potential cost overruns associated with nuclear construction;
- war or threat of war; and
- terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

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 could be limited and our financial condition and future results of operations could be adversely affected.

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 18% of our generating capacity and 39% of our energy generated during 2012. Our ownership interests in these facilities expose us to various risks, including:

- potential liabilities relating to harmful effects on the environment and human health resulting from the operation of these facilities and the on-site storage, handling and disposal of spent nuclear fuel;
- 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 or otherwise, including the payment of retrospective insurance premiums, whether at our own plants or the plants of other nuclear owners; and

- risks related to the expected cost, and funding of the expected cost, of decommissioning these facilities at the end of their operational life.

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.

A major incident at a nuclear facility anywhere in the world, such as the incident at the Fukushima Daiichi nuclear generating plant in Japan, 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.

Currently, there is no national repository for spent nuclear fuel, and progress towards such a repository has been disappointing. Spent nuclear fuel from Plants Hatch and Vogtle is currently stored in on-site storage facilities. We currently forecast that the on-site storage capabilities at Plants Hatch and Vogtle can be expanded to accommodate spent fuel through the life of the plants.

We maintain an internal fund and an external trust fund for the estimated cost of decommissioning our existing nuclear facilities. If the values of the investments in the funds significantly decrease or the anticipated decommissioning costs significantly increase, it is possible that decommissioning costs and liabilities could exceed the amount of these funds, and we would have to collect additional revenue from our members to pay the excess costs.

In addition to our existing ownership of 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 our operating agents 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;
- interruptions in fuel, water or material supplies;
- compliance with electric reliability organizations' mandatory reliability and record keeping standards, including mandatory cyber security standards;
- attacks on critical information technology systems or cyber intrusion;
- the ability to maintain a qualified workforce;
- labor disputes;
- terrorist attacks; or
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events such as influenzas or similar occurrences.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure. 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. 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.

A severe drought could reduce the availability of water and restrict or prevent the operation of certain generating facilities. These or similar negative events could 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 facilities that are operated by third parties. We rely on these operating agents for the continued operation of these facilities to avoid potential interruptions in service from these facilities. If our operating agents 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" for discussions of our relationship with Georgia Power and our co-owned facilities.

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 coal, natural gas and uranium. We have taken steps to manage this exposure by entering into fixed or capped price contracts for some of our coal requirements. We have also entered into natural gas swap arrangements designed to manage our and our members' exposure to fluctuations in the price of natural gas. 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. Therefore, 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.

We may not be able to obtain an adequate supply of fuel, which could limit our ability to operate our facilities.

We obtain our fuel supplies, including coal, natural gas and uranium, from a number of different suppliers. Any disruptions in our fuel supplies, including disruptions due to weather, labor relations, environmental regulations, inadequate infrastructure, or other factors affecting our fuel suppliers, could result in us having insufficient levels of fuel supplies. For example, natural gas supplies can be subject to disruption due to natural disasters and similar events. Any failure to maintain 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 affect their 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 over 20 to 30 years ago and, even if maintained in accordance with good engineering practices, may 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 a period of time, or other service-related interruptions. Further, the adoption of new environmental regulations could lead to significant capital expenditures for our older generating facilities to comply with the new environmental requirements.

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.

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, interest rate options, contracts related to the market price of coal and natural gas, power sales and purchases and facility construction. Many of these transactions expose us to the risk that our counterparty may fail to perform its contractual obligations.

For example, we have purchased interest rate options from several counterparties to hedge our exposure to rising interest rates on approximately $2.2 billion of expected borrowings related to the construction of Vogtle Units No. 3 and No. 4. Although our counterparties in these transactions have posted various amounts of collateral, if any of these counterparties fails or refuses to honor its obligations, those interest rate hedges may not provide the protection we anticipated. Failure of our counterparties to perform their contractual obligations under the interest rate options or any of our other agreements could significantly increase the cost of electric service we provide to our members.

Also, as a result of continued instability in global financial markets, some of our financial institution counterparties, including participants in our committed credit facilities, have experienced various degrees of financial distress, including liquidity constraints and credit downgrades. The financial distress of these counterparties may have an adverse effect on us in the event that these counterparties default or otherwise fail to meet 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.

Changes in power generation technology 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. Other technologies currently exist or are in development, such as fuel cells, micro turbines, windmills and solar cells, that may in the future be capable of producing electric power at costs that are comparable with, or lower than, our cost of generating power. If these technologies were to develop sufficient economies of scale, the value of our generating facilities could be adversely affected.

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 at times have an active trading market, certain of our debt securities have no active trading market, including some of our outstanding auction rate securities that have been subject to continued failed auctions since 2008. Various dealers have made a market in certain of our debt securities. We have remarketing agreements in place for certain of our variable rate bonds and if a particular series of new debt securities is offered through underwriters, those underwriters may attempt to make a market in the debt securities. 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. 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 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, all of which are in commercial operation.

Facilities	Type of Fuel	Percentage Interest	Our Share of Nameplate Capacity (MW)	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)
Unit No. 2	Coal	30	259.5	1978	N/A(1)
Combustion Turbine	Oil	30	14.8	1980	N/A(1)
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	2027
Doyle (near Monroe, Ga.)	Gas	100	325.0(2)	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)
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(3) (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-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 Federal Energy Regulatory Commission.

(2) Nominal plant capacity identified in the power purchase and sale agreement with Doyle I, LLC. (See "– The Plant Agreements – *Doyle.*")

(3) Formerly known as the Murray Energy Facility.

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) 2012	2011	2010	Capacity Factor(3) 2012	2011	2010
Plant Hatch							
Unit No. 1	262.2	88%	97%	84%	88%	98%	85%
Unit No. 2	264.3	98	78	95	98	78	96
Plant Vogtle							
Unit No. 1	344.5	90	89	100	91	91	102
Unit No. 2	344.7	100	93	91	102	94	93
Plant Wansley							
Unit No. 1	261.6	82	96	87	29	56	53
Unit No. 2	261.6	98	86	97	35	47	67
Combustion Turbine(4)	0	59	61	37	0	0	0
Plant Scherer							
Unit No. 1	501.2	99	75	99	69	64	89
Unit No. 2	509.0	99	76	98	73	66	90
Rocky Mountain(5)							
Unit No. 1	272.3	80	97	62	13	20	16
Unit No. 2	272.3	86	61	75	14	12	13
Unit No. 3	272.3	88	84	89	10	12	17
Doyle(5)	348.0	91	96	98	2	5	1
Talbot(5)	652.2	92	82	93	7	5	4
Chattahoochee	469.0	76	62	65	61	46	38
Hawk Road(5)	475.8	45	51	87	6	0	5
Hartwell(5)	298.0	86	94	93	2	8	7
Smith(6)							
Unit No. 1	630.0	81	89	n/a	42	34	n/a
Unit No. 2	620.0	86	79	n/a	32	21	n/a
TOTAL	7,059.0						

(1) Summer Planning Reserve Capacity is the amount used for 2013 capacity reserve planning.

(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) The Wansley combustion turbine is used primarily for emergency service and is rarely operated except for testing.

(5) Rocky Mountain, Doyle, Talbot, Hawk Road and Hartwell, primarily operate as peaking plants, which results in low capacity factors.

(6) The 2011 operating performance factors for Smith, which we acquired during 2011, are based on the entire twelve months of 2011.

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. Due to low gas and market prices relative to the contract price of coal for Plant Wansley, it has been dispatched at lower levels in recent years.

Fuel Supply

Coal. Coal for Plant Wansley is purchased under term contracts and in spot market transactions. As of February 28, 2013, we had a 113-day coal supply at Plant Wansley based on continuous operation.

Coal for Scherer Units No. 1 and No. 2 is purchased under term contracts and in spot market transactions. As of February 28, 2013, our coal stockpile at Plant Scherer contained a 43-day supply based on continuous operation. Plant Scherer burns sub-bituminous coal purchased from coal mines in the Powder River Basin in Wyoming.

We separately dispatch Plant Wansley and Plant Scherer, but use Georgia Power as our agent for fuel procurement. We currently lease approximately 1,200 rail cars to transport coal to these two facilities.

For information relating to the impact that the Clean Air Act may have on our coal-fired facilities, see "BUSINESS – REGULATION – Environmental – Air Quality."

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, 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 purchase transportation under long-term firm and short-term firm and non-firm contracts. We have also contracted with Petal Gas Storage, LLC to provide 800,000 MMBtu of firm natural gas storage services and related firm transportation. 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, the Municipal Electric Authority of Georgia, 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		Plant Wansley		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	696	30.0	519	60.0	982	74.61	633	3,369
Georgia Power	50.1	900	45.7	1,060	53.5	926	8.4	137	25.39	215	3,238
MEAG	17.7	318	22.7	527	15.1	261	30.2	494	–	–	1,600
Dalton	2.2	39	1.6	37	1.4	24	1.4	23	–	–	123
Total	100.0	1,796	100.0	2,320	100.0	1,730	100.0	1,636	100.00	848	8,330

(1) Based on nameplate ratings.

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 Valdosta, as well as in rural areas, and at wholesale to some of our members, the Municipal Electric Authority of Georgia 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 Power, 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 Power has wholesale take-or-pay power sales contracts with each of its 49 participants that extend to June 2054. The participants are located in 39 of the State's 159 counties and collectively serve approximately 309,000 electric consumers (meters). MEAG Power is the State'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. It presently serves more than 65,000 residential, commercial and industrial electric customers.

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 Power 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 Power, 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 institutional investors. 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 provided irrevocable notice to extend 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.

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 March 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 and Wansley ownership and operating agreements allow 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 and of Plant Wansley.

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 Plant Wansley will remain in effect with respect to Plant Wansley Units No. 1 and No. 2 until 2016 and 2018, respectively. The Operating Agreement for Scherer Units No. 1 and No. 2 will remain in effect with respect to Scherer Units No. 1 and No. 2 until 2022 and 2024, respectively. 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 (see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources"), we, Georgia Power, MEAG Power 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.

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 defined in the Rocky Mountain Operating Agreement) 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.

Rocky Mountain is subject to a lease-leaseback transaction. We continue to control and operate Rocky Mountain during the leaseback term. For more information about the structure of the lease transaction, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Off-Balance Sheet Arrangements – Rocky Mountain Lease Arrangements.*"

Doyle

We have an agreement with Doyle I LLC, a limited liability company owned by one of our members, Walton EMC, to purchase the output of a gas-fired combustion turbine generating facility through May 15, 2015.

During the term of the agreement, we have the right and obligation to purchase all of the capacity and energy from the facility. We are obligated to pay to Doyle I, LLC each month a capacity charge based on a performance rating and an energy charge equal to all costs of operating the facility. We are also obligated to pay the actual operation and maintenance costs and the costs of capital improvements. We are responsible for supplying all natural gas necessary to operate the facility. We have the right to dispatch the facility.

Doyle I, LLC operates the facility. Doyle I, LLC must make the units available from May 15 to September 15 each year. Subject to air permit and other limitations, we may dispatch the facility at other times to the extent that the facility is available.

We have an option to purchase the facility at the end of the term of the agreement at a fixed price. We account for this agreement as a capital lease of the facility for financial reporting purposes (see Note 6 of Notes to Consolidated Financial Statements).

ITEM 3. LEGAL PROCEEDINGS

See "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*" for a discussion of legal proceedings related to our participation in the construction of two additional units at Plant Vogtle.

In addition to the aforementioned litigation, we are a party to various other actions and proceedings incidental to our normal business. Our business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. 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. The ultimate outcome of pending or potential litigation against us cannot be predicted at this time; however, for current proceedings not specifically reported in this Item 3, management does 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 that could have an effect on us, see Note 13 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 our selected historical financial data. The financial data presented as of the end of and for each year in the five-year period ended December 31, 2012, has been derived from our 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)				
	2012	2011	2010	2009	2008
STATEMENTS OF REVENUES AND EXPENSES DATA					
Operating revenues:					
Sales to Members	**$ 1,204,008**	$ 1,224,238	$ 1,292,667	$ 1,144,012	$ 1,237,649
Sales to non-Members	**120,102**	166,040	1,478	1,249	1,111
Total operating revenues	**1,324,110**	1,390,278	1,294,145	1,145,261	1,238,760
Operating expenses:					
Fuel	**516,223**	531,147	501,113	391,001	462,138
Production	**371,909**	357,069	332,236	285,654	278,654
Purchased power	**50,022**	56,634	59,076	92,516	164,200
Depreciation and amortization	**160,849**	199,040	131,491	125,600	119,540
Accretion	**19,554**	18,249	17,131	18,261	17,149
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(16,280)**	(9,681)	13,849	8,107	–
Total operating expenses	**1,102,277**	1,152,458	1,054,896	921,139	1,041,681
Operating margin	**221,833**	237,820	239,249	224,122	197,079
Other income, net	**61,487**	44,264	43,651	42,728	43,381
Net interest charges	**(244,000)**	(244,347)	(249,167)	(240,460)	(221,201)
Net margin	**$ 39,320**	$ 37,737	$ 33,733	$ 26,390	$ 19,259
BALANCE SHEET DATA					
Electric plant, net:					
In service	**$ 4,034,620**	$ 4,007,281	$ 3,570,522	$ 3,557,723	$ 3,152,911
Nuclear fuel, at amortized cost	**321,196**	284,205	249,563	215,949	179,020
Construction work in progress	**2,240,920**	1,784,264	1,195,475	626,824	307,464
Total electric plant	**$ 6,596,736**	$ 6,075,750	$ 5,015,560	$ 4,400,496	$ 3,639,395
Total assets	**$ 8,314,566**	$ 8,078,829	$ 6,997,062	$ 6,370,234	$ 5,044,452
Capitalization:					
Long-term debt	**$ 5,930,449**	$ 5,692,503	$ 4,796,154	$ 4,267,966	$ 3,361,463
Obligations under capital leases	**161,249**	191,900	212,561	239,461	264,107
Obligations under Rocky Mountain transactions	**14,392**	132,048	123,573	115,641	108,219
Patronage capital and membership fees	**673,009**	633,689	595,952	562,219	535,829
Accumulated other comprehensive loss	**903**	618	(469)	(1,253)	(1,348)
Subtotal	**6,780,002**	6,650,758	5,727,771	5,184,034	4,268,270
Less: long-term debt and capital leases due within one year	**(168,393)**	(172,818)	(170,947)	(119,241)	(110,647)
Less: unamortized bond discounts on long-term debt	**(3,232)**	(1,879)	(1,353)	(260)	–
Total capitalization	**$ 6,608,377**	$ 6,476,061	$ 5,555,471	$ 5,064,533	$ 4,157,623
Property additions	**$ 646,486**	$ 839,503	$ 669,206	$ 627,148	$ 353,831
OTHER DATA					
Energy supply (megawatt-hours):					
Generated	**24,883,009**	22,296,829	22,599,257	19,699,706	21,906,888
Purchased	**107,104**	287,522	417,094	779,108	1,755,225
Available for sale	**24,990,113**	22,584,351	23,016,351	20,478,814	23,662,113
Member revenues per kWh sold	**5.77¢**	6.25¢	5.71¢	5.67¢	5.31¢

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

Executive Overview

General

We are a not-for-profit electric cooperative whose principal business is providing wholesale electric service to our 38 members. Consequently, the vast majority of our revenues and cash flow are derived from sales to our members pursuant to long-term, 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 receive sufficient capacity-related revenues. This structure provides us with the ability to manage our revenues to assure full recovery of our costs in rates and has enabled us to consistently meet our financial obligations since our formation in 1974.

2012 Financial Results

Despite continuing economic pressures, we remain well positioned, both financially and operationally, to fulfill our obligations to our members, bondholders and creditors. In this regard, our revenues in 2012 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 $39.3 million in 2012, which achieved the 1.14 margins for interest ratio approved by our board of directors and exceeded the margins for interest ratio of 1.10 required to meet the rate covenant under our first mortgage indenture.

In light of financial market conditions and increased capital requirements, we believe it was prudent to increase our margins for interest coverage. Since 2009, we have targeted and achieved higher margins than necessary to meet our margins for interest ratio covenant of 1.10 required under the first mortgage indenture. As a result of the margins achieved over this timeframe, our patronage capital has increased to $673 million at December 31, 2012 from $536 million at December 31, 2008. For 2013, we are again targeting a margins for interest ratio of 1.14, effectively increasing our annual margins by 40% over the minimum required level.

In connection with expanding our generation capacity and upgrading our generation facilities, our total assets have increased to $8.3 billion at December 31, 2012 from $5.0 billion at December 31, 2008, and our total debt has increased to $6.5 billion from $3.4 billion during the same period. As we continue to construct Vogtle Units No. 3 and No. 4 and update our other facilities to meet applicable environmental requirements, our assets and debt will both continue to increase.

Asset Management

From 2008 through 2011, we focused considerable efforts on the development and acquisition of additional generation resources that provide our members, through us, greater ownership and control over their power supply resources in order to mitigate their reliance on third-party contracts. In 2012, we shifted our focus to further ensure that our owned and operated generation facilities perform in the most efficient and cost-effective manner possible. As a primary means to achieve this goal, we implemented an Operational Excellence program to achieve top-tier performance in the areas of safety, reliability, cost effectiveness and compliance. Many of the generation facilities we operate rank in the top quartile of similar plants in one or more key performance indicators, including start reliability, peak season availability and forced outages. Achieving operational excellence results in the most reliable, efficient and lowest cost power supply for our members; therefore, effective asset management will continue to be one of our top priorities.

A key component in this effort is maintaining compliance with all applicable environmental, reliability and other regulatory standards. We forecast that capital expenditures required for existing generating facilities will be approximately $483 million through 2015, which includes normal additions and replacements to existing plants as well as projects to maintain and achieve compliance with current environmental requirements. However, this forecast does not include capital expenditures or increased operational expenses due to climate change or coal combustion by-products regulation that might be adopted in the future.

Although we are no longer actively seeking to acquire additional generation resources, we remain firmly committed to the construction of Vogtle Units No. 3 and No. 4. It should be noted that we will continue to evaluate exceptional opportunities to acquire additional generation resources as these opportunities arise.

Vogtle Units No. 3 and No. 4

Through our agent, Georgia Power, we and the other Co-owners of Plant Vogtle have contracted with Southern Nuclear, Westinghouse and Stone & Webster, experienced developers and contractors, to construct two additional nuclear units at the Plant Vogtle site. These units will have an aggregate generating capacity of approximately 2,200 megawatts and our 30% undivided interest will entitle us to approximately 660 megawatts of baseload generating capacity. In early 2012, the Nuclear Regulatory Commission issued the combined construction permits and operating licenses for these units, the first licenses granted to construct new nuclear units in the United States in over 30 years.

Overall, we are encouraged by the construction activity and progress at the Plant Vogtle site as the Contractor moves forward with preliminary and critical path activities. We, along with the other Co-owners, have an uncompromising focus on safety and quality in the construction of these units and are focused on working with the Contractor and Nuclear Regulatory Commission to ensure that this project meets the rigorous safety standards applicable to this "first of a kind" endeavor. As is often the case in the construction of large, complex generation facilities, issues have materialized during the course of development and construction that have caused revisions to the original schedule and budget. In early 2013, Georgia Power revised the expected commercial operation dates for Vogtle Units No. 3 and No. 4 to the fourth quarter of 2017 and 2018, respectively, and we revised our estimated total cost to $4.5 billion. We and the other Co-owners are currently in litigation with the Contractor regarding the cost responsibility for certain of these delays; however, we expect negotiations to continue during this litigation. Of course, the outcome of this litigation and the emergence of additional issues could lead to further schedule or budget revisions.

As of December 31, 2012, our capitalized costs for the additional units at Plant Vogtle were approximately $1.7 billion and we have secured long-term financing for approximately $1.4 billion of these costs through the issuance of taxable first mortgage bonds. We and the Department of Energy have executed a conditional commitment letter for a long-term loan guarantee for up to $3.057 billion of eligible project costs which remains subject to the negotiation and acceptance of final terms. We expect that we will finance additional project costs in the capital markets, including any amounts not funded through the Department of Energy loan guarantee program.

Liquidity Position

One of the most positive attributes contributing to our solid financial standing is our strong liquidity position. 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 $1.265 billion unsecured credit facility, which also supports our commercial paper program. We have another $250 million under a secured facility and $410 million under unsecured credit facilities. At December 31, 2012, we had $1.4 billion of unrestricted available liquidity.

In addition to maintaining more than adequate coverage for short-term credit needs, we have also taken advantage of historically low interest rates to secure favorable long-term financing for some of our construction and acquisition activity. The Rural Utilities Service has approved or advanced loans to provide long-term funding for our acquisition of Hawk Road, Hartwell and Smith. We are also active in the capital markets where, over the past three years, we have successfully issued $1 billion in taxable registered bonds and refinanced nearly $350 million of tax-exempt bonds.

Outlook for 2013

We remain focused on providing reliable, cost-effective energy to our members and the 4.1 million people they serve. There are, nevertheless, certain risks and challenges that we must address, including:

- Further revisions to the estimated commercial operation dates and total in-service costs for Vogtle Units No. 3 and No. 4;
- Managing the effects of increased environmental regulation of fossil fuel-fired power plants, most

likely leading, for example, to new costs or regulations related to greenhouse gases or other air emissions, coal combustion by-products, or wastewater discharges, particularly at Plants Scherer and Wansley;

- Continued ability to access financial markets and availability of federally-guaranteed funding to support our significant future capital requirements; and
- General economic conditions in the U.S. and the related impacts on our members and their consumers.

We believe that we continue to be well positioned to provide reliable, cost-effective energy to our members and their consumers. As we manage our risks, we intend to keep doing what we have done so successfully for the last 39 years, including, among other things:

- Maintaining a balanced diversity of generating resources – primarily nuclear, coal, natural gas and hydro and continuing the 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, as opportunities arise, to evaluate new resources to be acquired or developed by us to help meet our members' power supply requirements.

Summary of Cooperative Operations

Margins and Patronage Capital

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. Revenues in excess of current period costs in any year are designated as net margin in our statements of revenues and expenses. Retained net margins are designated on our balance sheets as patronage capital, which is allocated to each of our members on the basis of its fixed percentage capacity costs responsibilities in our generation and purchased power resources. Since our formation in 1974, we have generated a positive net margin in each year and had $673 million in patronage capital and membership fees as of December 31, 2012. Our equity ratio, calculated as patronage capital and membership fees divided by total capitalization and long-term debt due within one year, was 9.9% at December 31, 2012 and 9.5% at December 31, 2011.

Patronage capital constitutes our principal equity. Any distribution of patronage capital is subject to the discretion of our board of directors. However, under the 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 not less than 30% of our total long-term debt and equities.

Rates and Regulation

Pursuant to the wholesale power contracts between us and each of our members, we are required to design capacity and energy rates that generate revenues sufficient to recover all costs, including the 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 rate schedule under the wholesale power contracts assigns on a long-term basis, the responsibility for our fixed costs to each of our members. The monthly charges for capacity and other non-energy charges are based on a rate formula using our budget. Energy charges are based on actual energy costs, including fuel costs, variable operations and maintenance costs, and purchased energy costs.

Under the 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. The margins for interest ratio is determined by dividing margins for interest by interest charges. Margins for interest equals the sum of (i) our net margins (after certain defined adjustments), (ii) interest charges and (iii) any amount included in net margins for accruals for federal or state income taxes. The definition of 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 such 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 such losses or expenditures. The interest charges in the margins for interest ratio is comprised of interest on debt secured under our first mortgage indenture.

We review our financial results frequently 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 budgeted margins for interest ratio. In the event we were to fall short of the minimum 1.10 margins for interest ratio required under the first mortgage indenture at year end, the rate schedule includes a prior period adjustment mechanism designed to recover the shortfall without any additional action by our board of directors. Amounts, if any, by which we fall short of the minimum 1.10 margins for interest ratio would be accrued as of December 31 of the applicable year and collected from our members from April through December of the following year.

Prior to 2009, we budgeted and achieved an annual margins for interest ratio 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 a margins for interest ratio in excess of the minimum 1.10 ratio required by the first mortgage indenture. In 2010, 2011 and 2012, we 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 2013. 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.

Under the first mortgage indenture and related loan contract with the Rural Utilities Service, adjustments to our rates to reflect changes in our budgets are generally not subject to Rural Utilities Service approval. Changes to the rate schedule under the wholesale power contracts are generally subject to Rural Utilities Service approval. Our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

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.

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, 2012, our regulatory assets and liabilities totaled $353 million and $130 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 liabilities that had been recognized as a charge 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.

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. In addition, we also make interest rate and rate of return projections on investments in determining recommended funding requirements for nuclear decommissioning costs.

A significant portion of our asset retirement obligations relates to our share of the future cost to decommission our operating nuclear units. At December 31, 2012, our nuclear decommissioning asset retirement obligation totaled $327.8 million, which represented approximately 86% of our total asset retirement obligations. Our remaining asset retirement obligations relate to non-nuclear retirement obligations such as those related to our share of coal facilities.

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 by third-party experts. The third party experts 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 future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption. Our current estimates are based upon studies that were performed in 2012 and adopted December 31, 2012. For ratemaking purposes, we record decommissioning costs over the expected service life of each unit based on studies. The impact on measurements of asset retirement obligations using different assumptions in the future may be significant.

New Accounting Pronouncements

In May 2011, the FASB issued "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards." The amendments change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, but generally do not result in a change in the application of ASC 820 "Fair Value Measurements." These changes were effective for us on January 1, 2012. Our adoption of this standard did not have a material effect on our consolidated financial statements.

In June 2011, the FASB issued "Comprehensive Income (Topic 220) Presentation of Financial Statements" which amended certain provisions of ASC 220 "Comprehensive Income." These provisions change the presentation requirements for other comprehensive income and total comprehensive income and require one continuous statement or two separate but consecutive statements. Presentation of other comprehensive income in the statement of stockholders' equity is no longer permitted. These provisions are effective for fiscal and interim periods beginning after December 15, 2011. The adoption of these provisions did not have a material effect on our consolidated financial statements.

In December 2011, the FASB issued "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities," which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. This guidance is effective for our fiscal year ending December 31, 2013. We do not expect the adoption of this standard to have a material impact on our consolidated financial statements.

Results of Operations

Net Margin

Our net margin for the years ended December 31, 2012, 2011 and 2010 was $39.3 million, $37.7 million and $33.7 million, respectively. These amounts produced respective margins for interest ratios of 1.14 in 2012, 2011 and 2010. The margins for interest ratios achieved were greater than the minimum required under our first mortgage indenture. Our margin requirement is based on a ratio applied to interest charges on debt secured by our first mortgage indenture. 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.

As our construction program evolves, 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 the 1.10 margins for interest ratio required under our first mortgage indenture. For 2013 our board of directors approved a budget to achieve a margins for interest of 1.14. For additional information on our margin requirement, see "– Summary of Cooperative Operations – *Rates and Regulation.*"

Operating Revenues

Sales to Members. We generate revenues principally from the sale of electric capacity and energy.

- Capacity revenues are derived primarily from electric capacity sales to our members under the wholesale power contracts. The members have contractually agreed to pay us for the electric capacity they obtain from us to meet their operating requirements. We receive capacity revenues whether or not our generation assets, including power purchase contracts, are dispatched to produce electricity.
- Energy revenues are earned by selling electricity to our members, which involves generating or purchasing electricity for our members.

Our kilowatt-hour sales to our members, one of the primary drivers of our operating revenues, fluctuate from period to period based on several factors, including weather and other seasonal factors, load requirements in the service territories of our members, operating costs, 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.

Total revenues from sales to members decreased by 1.7% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and decreased by 5.3% for the year ended December 31, 2011 compared to the year ended December 31, 2010. The components of member revenues were as follows:

	(dollars in thousands)		
	2012	2011	2010
Capacity revenues	**$ 675,467**	$ 685,045	$ 677,049
Energy revenues	**528,541**	539,193	615,618
Total	**$ 1,204,008**	$ 1,224,238	$ 1,292,667

Capacity revenues relate primarily to the assignment to each of our members of the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges. Each member is required to pay us for capacity furnished under its wholesale power contract in accordance with rates we establish.

Capacity revenues from members varied slightly for fiscal years 2012, 2011 and 2010. Our capacity revenues vary proportionately to changes in our margins, changes in fixed costs and changes in other income. See "– *Operating Expenses*", "– *Other Income*" and "– *Interest Charges*" below for discussion of increases or decreases within each of these sections.

Energy revenues relate primarily to the pass-through to our members of the variable costs, such as fuel costs, variable operation and maintenance costs and purchased energy costs, associated with our business. Each member is required to pay us for energy we furnish it under its wholesale power contract, in accordance with rates we establish.

Energy revenues from members decreased 2.0% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and decreased 12.4% for the year ended December 31, 2011 compared to the year ended December 31, 2010. Energy revenues from members were lower in 2012 as compared to 2011 primarily due to lower generation at coal-fired Plant Wansley driven by the availability of more economical generation from our natural gas-fired facilities. Energy revenues were lower in 2011 as compared to 2010 primarily due to lower kilowatt-hour sales to our members primarily as a result of a planned outage at Plant Scherer which resulted in lower generation available to members. For a discussion of fuel costs, see "– *Operating Expenses.*"

The following table summarizes the kilowatt-hours sold to members and total revenues per kilowatt-hour during each of the past three years:

	(in thousands)	Cents per Kilowatt-hour
2012	**20,852,826**	**5.77**
2011	19,574,145	6.25
2010	22,644,790	5.71

For the year ended December 31, 2012 compared to the year ended December 31, 2011, kilowatt-hour sales to members increased 6.5% and for the year ended December 31, 2011 as compared to the year ended December 31, 2010, kilowatt-hour sales to members decreased 13.6%. The average revenue per kilowatt-hour from sales to members decreased 7.7% and increased 9.5% for 2012 compared to 2011 and for 2011 compared to 2010, respectively. An increase in kilowatt-hours of generation was the primary reason for increased kilowatt-hours sold to members in 2012. Decreases in kilowatt-hours of generation sold to our members and kilowatt-hours of purchased power were the reasons for decreased kilowatt-hours sold to members in 2011. For further discussion regarding fuel and purchased power costs, see "– *Operating Expenses*."

We pass through actual energy costs to our members such that energy revenues equal energy costs. The energy portion of member revenues per kilowatt-hour decreased 8.0% for the year ended December 31, 2012 as compared to the year ended December 31, 2011 and increased 1.3% for the year ended December 31, 2011 compared to the year ended December 31, 2010. The higher average revenues per kilowatt-hour in 2011 as compared to 2012 and 2010 were primarily due to the pass-through of higher fuel costs. For further discussion regarding fuel costs, see "– *Operating Expenses*."

Sales to Non-members. Our sales to non-members in 2012 and 2011 consist of capacity and energy sales to Georgia Power, as well as energy sales to other non-members. These capacity and energy sales are primarily associated with Smith, which we acquired in April 2011. The agreement with Georgia Power, which was for the sale of the entire output of Unit No. 1 of Smith, expired on May 31, 2012. The decrease in 2012 as compared to 2011 was primarily due to lower capacity payments from Georgia Power as a result of the expiration of the agreement described above. For information regarding the acquisition of Smith, see Note 14 of Notes to Consolidated Financial Statements.

Operating Expenses

Our operating expenses decreased 4.4% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and increased 9.2% for the year ended December 31, 2011 compared to the year ended December 31, 2010. The decrease in 2012 as compared to 2011 was primarily due to lower fuel costs and depreciation and amortization expenses offset somewhat by higher production expenses. The increase in 2011 as compared to 2010 resulted primarily from higher fuel costs, production costs and depreciation and amortization.

The following table summarizes our megawatt-hour generation and fuel costs by generating source and purchased power costs.

	Year Ended December 31,								
	2012			2011			2010		
Fuel Source	**Cost**	**Generation**	**Cost per Mwh**	Cost	Generation	Cost per Mwh	Cost	Generation	Cost per Mwh
	(thousands)	**(Mwh)**		(thousands)	(Mwh)		(thousands)	(Mwh)	
Coal	**$ 229,427**	**7,691,759**	**$ 29.83**	$ 233,525	7,640,089	$ 30.57	$ 298,224	10,591,595	$ 28.16
Nuclear	**81,724**	**10,182,492**	**8.03**	74,815	9,691,869	7.72	65,917	10,053,614	6.56
Gas	**203,189**	**7,379,749**	**27.53**	219,487	5,369,874	40.87	135,094	2,343,250	57.65
Pumped Storage	**1,883**	**976,148**	**1.93**	3,320	996,234	3.33	1,878	986,192	1.90
	$ 516,223	**26,230,148**	**$ 19.68**	$ 531,147	23,698,066	$ 22.41	$ 501,113	23,974,651	$ 20.90

	Cost	**Purchased**	**Cost per Mwh**	Cost	Purchased	Cost per Mwh	Cost	Purchased	Cost per Mwh
	(thousands)	**(Mwh)**		(thousands)	(Mwh)		(thousands)	(Mwh)	
Purchased Power	**$ 50,022**	**107,104**	**$467.04**	$ 56,634	287,522	$196.97	$ 59,076	417,094	$141.64

Total fuel costs decreased 2.8% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and increased 6.0% for the year ended December 31, 2011 as compared to the year ended December 31, 2010 while total generation increased 10.7% and decreased 1.2% for the same periods, respectively. Average fuel cost per kilowatt-hour decreased 12.2% in 2012 compared to 2011 and increased 7.2% in 2011 compared to 2010. The decrease in total and average fuel costs for 2012 as compared to 2011 resulted primarily from lower natural gas prices and lower generation at Plant Wansley offset somewhat by higher generation at Plant Scherer. The decrease in total cost was offset by higher nuclear generation. Natural gas-fired generation increased 2,010,000 megawatt-hours in 2012 as compared to 2011 driven by increases at Smith and Chattahoochee. The generation from Smith was utilized for non-member sales, thus there was little impact to members from generation at Smith. The lower generation at Plant Wansley was primarily driven by the availability of more economical generation from our natural gas-fired facilities. Our generation from Plant Wansley in 2012 was lower by 849,000 megawatt-hours from the prior year level. In 2012, Plant Scherer generation was higher by 900,000 megawatt-hours as compared to 2011 due to fewer scheduled outages in 2012. The increase in 2012 nuclear generation, which is our most economical resource based on average fuel cost, contributed to the decrease in average fuel cost as well. The increase in total and average fuel costs for 2011 as compared to 2010 resulted primarily from a change in the mix of generation with an increase in higher priced natural gas-fired generation of 3,027,000 megawatt-hours primarily offset by a decline in coal-fired generation of 2,952,000 megawatt-hours as well as a small decrease in nuclear generation of 362,000 megawatt-hours. The increase in natural gas-fired generation was primarily due to the Smith acquisition while the decrease in coal-fired generation was due to a scheduled outage at Plant Scherer for the installation of environmental compliance equipment and for the performance of general maintenance.

The changes in total fuel costs are also impacted by the amounts of realized gains and losses incurred for natural gas financial hedging contracts utilized for managing exposure to fluctuations in the market prices of natural gas. For 2012, 2011 and 2010 we incurred net realized losses of $9.3 million, $4.0 million and $19.7 million, respectively.

Production costs increased 4.2% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and increased 7.5% for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The increase in production costs for 2012 as compared to 2011 was primarily due to operations and maintenance expenses incurred at Smith, which was acquired in April 2011, increased general operation and maintenance expense at Plants Vogtle, Hatch and Wansley and increased operations and contractual maintenance fees at Chattahoochee which are based on equivalent operating hours. These increases were offset somewhat by lower production costs at Hawk Road as production costs in 2011 included expenses for planned outage work and for repair of a damaged transformer. The increase for 2011 compared to 2010 resulted from operations and maintenance expenses at Smith and from the Hawk Road outage expenses. The increases were offset somewhat by lower operations and maintenance costs at Hartwell which incurred planned maintenance outage costs in 2010. Reductions in property taxes at the jointly-owned plants helped to offset the above mentioned increases in 2011 as compared to 2010. For information regarding Smith, see Note 14 of Notes to Consolidated Financial Statements.

Purchased power costs decreased 11.7% for the year ended December 31, 2012 as compared to the year ended December 31, 2011 and decreased 4.1% for the year ended December 31, 2011 compared to the year ended December 31, 2010. Purchased kilowatt-hours decreased 62.7% in 2012 compared to 2011 and decreased 31.0% for 2011 compared to 2010. These decreases in purchased power costs resulted primarily from a decrease in kilowatt-hours acquired under our energy replacement program, which replaces power from our owned generation facilities with power purchased on the spot market at a lower price.

Depreciation and amortization expense decreased 19.2% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and increased 51.4% for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The decrease in depreciation and amortization in 2012 as compared to 2011 resulted primarily from lower amortization costs in 2012 for the intangible asset associated with the purchase and sale agreement with Georgia Power, which expired May 31, 2012, acquired as part of the Smith acquisition. The 2011 write-off of two discontinued projects was also responsible for the decrease in depreciation and amortization in the current year. The increase in depreciation and amortization in 2011 as compared to 2010 resulted primarily from depreciation at Smith as well as the amortization of the intangible asset described above. In addition, the increase in depreciation and amortization for 2011 as compared to the prior year was also related to amortization of costs associated with discontinued preliminary construction activities for two generation projects and due to higher depreciation for Plants Scherer and Wansley related to environmental compliance projects recently placed into service. The additional capital improvements at Plants Scherer and Wansley resulted in higher depreciation rates which became effective January 1, 2011.

The effect on net margin of Smith and Hawk Road is being deferred until 2016 at which time the amounts will be amortized over the remaining life of the plants. In implementing the deferral plans, we assumed that our members would generally not require energy from the plants until 2016. If any of our members subscribed to Smith elect to take energy from Smith prior to 2016, the deferral of the effect on net margin would terminate for that member and the amortization of that member's deferral would commence immediately. The change in cost deferrals in 2012 as compared to 2011 and in 2011 as compared to 2010 resulted from the Smith and Hawk Road costs discussed above in production costs. For additional information regarding Smith, see Note 14 of Notes to Consolidated Financial Statements.

Other Income

The gain on termination of Rocky Mountain transactions represents the net gain resulting from the July and October 2012 termination of five of six leases. The net gain includes termination costs of $22.5 million as well as recognizing $41.4 million of the deferred net benefit associated with the terminated leases resulting in a net gain of $18.9 million. For further discussion regarding termination of Rocky Mountain transactions, see Note 4 of Notes to Consolidated Financial Statements.

Interest Charges

Interest on long-term debt and capital leases increased by 3.8% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and increased 11.1% for the year ended December 31, 2011 compared to the year ended December 31, 2010. The increases in 2012 and 2011 as compared to the same prior year periods are primarily due to the increased debt issued to finance the construction of Vogtle Units No. 3 and No. 4.

Allowance for debt funds used during construction increased by 15.4% for 2012 compared to 2011 and by 74.8% for 2011 compared to 2010 primarily due to capital expenditures for Plant Scherer and Vogtle Units No. 3 and No. 4.

Amortization of debt discount and expense decreased 2.3% for the year ended December 31, 2012 compared to the year ended December 31, 2011 and decreased 13.3% for the year ended December 31, 2011 compared to the year ended December 31, 2010. The decrease in 2011 compared to 2010 was primarily due to the completed amortization in December 2010 of issuance costs associated with transactions that closed in May and August 2009 to provide supplemental credit enhancement for the Rocky Mountain lease arrangements.

Financial Condition

Overview

Consistent with our budgeted margin for 2012, we achieved a 1.14 margins for interest ratio which produced a net margin of $39.3 million. This net margin increased our total patronage capital (our equity) and membership fees to $673.0 million at December 31, 2012. Our 2013 budget again targets a 1.14 margins for interest ratio.

Our equity to total capitalization ratio increased from 9.5% at December 31, 2011 to 9.9% at December 31, 2012. In recent years our equity to capitalization ratio has been decreasing due to the amount of new debt we have incurred in connection with the expansion of our generation fleet. However, in connection with the termination of five of our six Rocky Mountain lease arrangements, our Obligation under Rocky Mountain transactions decreased by $118 million in 2012, causing our equity to capitalization ratio to increase this year. For a discussion of the Rocky Mountain lease terminations, see "*– Off-Balance Sheet Arrangements – Rocky Mountain Lease Arrangements.*" During the peak years of the Plant Vogtle construction, we anticipate that our equity to capitalization ratio will continue declining even though the absolute level of margins and patronage capital are increasing,

We had a strong liquidity position at December 31, 2012, with $1.4 billion of unrestricted available liquidity, including $299 million of cash.

Our total assets increased to $8.3 billion at December 31, 2012 from $8.1 billion at December 31, 2011. The majority of this increase relates to an increase in total electric plant in connection with constructing the additional units at Plant Vogtle.

We maintained adequate access to capital throughout 2012, issuing more than $260 million of long-term debt in the capital markets. We also utilized shorter-term credit arrangements, including commercial paper and a three-year bank term loan, to provide interim financing for the Plant Vogtle construction and the Smith acquisition at a very low cost. The average cost of funds on the $830 million of interim financing outstanding at December 31, 2012 was 0.76%. See "*– Financing Activities*" for a discussion of the long-term financing of these facilities.

There was a net increase in long-term debt of $221 million at December 31, 2012 compared to December 31, 2011. This net increase was due to: i) the issuance of $250 million of first mortgage bonds and ii) $107 million of funds advanced under Rural Utilities Service-guaranteed loans during the year. The weighted average interest rate on the $5.9 billion of long-term debt outstanding at December 31, 2012 was 4.7%.

Property additions and plant acquisitions during 2012 totaled $646 million and were financed with a combination of funds from operations and short-term and long-term borrowings. This includes costs related to the construction of the new Plant Vogtle units, environmental control facilities being installed at Plant Scherer, normal additions and replacements to existing generation facilities and purchases of nuclear fuel.

Sources of Capital and Liquidity

Sources of Capital. Our operations have historically provided a sizable contribution to the funding of capital requirements, such that internally generated funds have provided interim funding or long-term capital for nuclear fuel purchases, replacements and additions to existing generation facilities, general plant additions, and retirement of long-term debt. However, due to the significant amount of expenditures relating to environmental compliance projects underway at Plants Scherer and Wansley, the construction of the new units at Plant Vogtle and the acquisitions of gas-fired generation, we are currently funding our capital requirements through a combination of funds generated from operations and short-term and long-term borrowings.

We have historically obtained the majority of our long-term financing from Rural Utilities Service-guaranteed loans funded by the Federal Financing Bank. However, Rural Utilities Service funding levels are uncertain and may be limited at any point in the future due to budgetary and political pressures faced by Congress. The President's budget proposal for fiscal year 2013, which started on October 1, 2012, provides for $6.1 billion in loans – a reduction of less than 10% from 2012 levels. Not more than $2 billion could be made available for environmental improvements to fossil-fueled generation that would reduce emissions, with the remaining funding limited to renewable energy, transmission, distribution and carbon-capture projects on generation facilities, and low emission peaking units affiliated with energy facilities that produce electricity from solar, wind and other intermittent sources of energy. Although Congress has historically rejected proposals to dramatically curtail the Rural Utilities Service loan program, there can be no assurances that it will continue to do so. 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. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with the Rural Utilities Service."

We have also obtained a substantial portion of our long-term financing requirements from the issuance of bonds in the taxable and tax-exempt capital markets, and expect to continue to access these markets in the future. However, the types of equipment that will qualify for tax-exempt financing are fewer than in the past due to changes in tax laws and regulations.

Additionally, in connection with a federal loan guarantee program established under the Energy Policy Act of 2005, we have signed a conditional term sheet with the Department of Energy for up to $3.057 billion of the estimated $4.5 billion cost to construct our 30% undivided share of the two new nuclear units at Plant Vogtle.

Therefore, any generation facilities that we are building or may build or acquire in the future will likely be financed long-term through a variety of sources. See *"– Capital Requirements – Capital Expenditures"* for more detailed information regarding our estimated capital expenditures. See "– *Financing Activities*" for more detailed information regarding our financing plans.

Liquidity. At December 31, 2012, we had $1.4 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of $299 million of cash and cash equivalents and $1.1 billion of unused and available committed short-term credit arrangements.

Net cash provided by operating activities was $156 million in 2012, and averaged $208 million per year for the three-year period 2010 through 2012.

At December 31, 2012, we had in excess of $1.9 billion of committed credit arrangements in place comprised of five separate facilities as reflected in the table below:

Committed Line of Credit Facilities

(dollars in millions)

	Authorized Amount	Available 12/31/2012	Expiration Date
Unsecured facilities:			
Syndicated Line led by Bank of America	$ 1,265	$ 560(1)	June 2015
Syndicated Line led by CoBank	150	150	September 2014
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	33(2)	December 2013
Secured facilities:			
CFC Line of Credit	250	250	December 2013
Total	**$ 1,925**	**$ 1,103**	

(1) Of the portion of this facility that is unavailable, $569 million is dedicated to support commercial paper we have issued and $136 million relates to letters of credit issued to support variable rate demand bonds.

(2) Of the portion of this facility that is unavailable, $114 million relates to letters of credit issued to support variable rate demand bonds and $3 million relates to letters of credit issued to post collateral to third parties.

We have the flexibility to use the $1.265 billion syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up outstanding commercial paper.

Under our commercial paper program we are authorized to issue commercial paper in amounts that do not exceed the amount of any committed backup lines of credit, thereby providing 100% dedicated support for any commercial paper outstanding.

Under our unsecured committed lines of credit, we have the ability to issue letters of credit totaling $835 million in the aggregate, of which $583 million remained available at December 31, 2012. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under our committed credit facilities for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue. The majority of our outstanding letters of credit are for the purpose of providing credit enhancement on variable rate demand bonds.

We are currently issuing commercial paper to provide interim funding for (i) payments related to the construction of Vogtle Units No. 3 and No. 4, (ii) a portion of the cost to acquire Smith, (iii) the refinancing on an interim basis of certain pollution control revenue bonds, and (iv) the upfront payments made in connection with the interest rate hedging program. For a discussion of the Plant Vogtle construction, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*." For a discussion of the Smith acquisition, see Note 14 of Notes to Consolidated Financial Statements. For a discussion of our plans regarding permanent financing for Vogtle Units No. 3 and No. 4, the Smith acquisition and our refinancing of pollution control revenue bonds, see "– *Financing Activities*." For a discussion of the interest rate hedging program, see "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK – Interest Rate Risk."

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 financing for the new Vogtle units under construction.

Several 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 $575 million. As of December 31, 2012, our patronage capital balance was $673 million. An additional covenant contained in several of our credit facilities limits our secured indebtedness to $9.5 billion and unsecured indebtedness to $4.0 billion. At December 31, 2012, we had approximately $5.8 billion of secured indebtedness outstanding and $935 million of unsecured indebtedness outstanding.

Under the $250 million line of credit with National Rural Utilities Cooperative Finance Corporation (CFC), we have the option of converting any amounts outstanding under the line of credit to a term loan with a maturity no later than December 31, 2043. Any amounts drawn under this line of credit, as well as any amounts converted to a term loan, will be secured under the first mortgage indenture.

Under a power bill prepayment program we offer, 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. Since the program began, we have received a total of $538 million in power bill prepayments from 22 members who have participated in the program. Currently, the balance remaining to be applied against future power bills is $190.5 million.

In addition to unrestricted available liquidity, at December 31, 2012 we had $64.8 million of restricted liquidity including $64.7 million in restricted short-term investments pursuant to deposits made into a Rural Utilities Service Cushion of Credit Account. The deposits in the Cushion of Credit Account were made voluntarily and earn a guaranteed rate of interest of 5% per annum. The funds in the account, including interest thereon, can only be applied to debt service on Rural Utilities Service notes and Rural Utilities Service-guaranteed Federal Financing Bank notes. From time to time we may deposit additional funds into the Cushion of Credit Account. An additional $138.2 million was deposited into the Cushion of Credit Account subsequent to December 31, 2012.

Liquidity Covenants. At December 31, 2012, we had only one financial agreement in place containing a liquidity covenant. This covenant is in connection with the remaining 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 2012 and expect to have sufficient liquidity to meet this covenant in 2013.

Financing Activities

First Mortgage Indenture. Our first mortgage debt is secured equally and ratably under the first mortgage indenture by a lien on substantially all of our tangible and some of our intangible assets, including those we acquire in the future. The mortgaged property includes our electric generating plants and some of our contracts for the purchase, sale or transmission of electricity of more than one year in duration or that relate to the ownership, operation, construction or maintenance of our electric generation facilities. At December 31, 2012, we had $5.67 billion outstanding under the first mortgage indenture.

Smith, which we acquired in 2011, is currently owned by one of our wholly owned subsidiaries and not directly by us. Consequently, Smith is not currently included in the mortgaged property; however, we anticipate that it will become part of the mortgaged property by the second quarter of 2013.

Rural Utilities Service-Guaranteed Loans. We currently have six approved Rural Utilities Service-guaranteed loans, funded through the Federal Financing Bank, totaling $1.7 billion that are in various stages of being drawn down, with $996 million remaining to be advanced. Included in the approved loans is a $493 million loan covering the majority of the acquisition cost of Smith. We anticipate that the Smith loan will be closed and fully funded by the second quarter of 2013.

All of the approved Rural Utilities Service loans will be funded through the Federal Financing Bank and guaranteed by the Rural Utilities Service, and the debt will be secured under our first mortgage indenture.

Department of Energy-Guaranteed Loan. The Department of Energy loan guarantee program was authorized pursuant to Title XVII of the Energy Policy Act of 2005, which is intended to support innovative technologies to reduce air pollutants, including greenhouse gases. Pursuant to this program, in May 2010 we signed a conditional term sheet with the Department of Energy that sets forth the general terms of a loan and related loan guarantee that would fund up to $3.057 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. The loan structure would entail a loan that is funded by the Federal Financing Bank carrying a federal loan guarantee provided by the Department of Energy, with the debt secured ratably with all other debt under our first mortgage indenture.

Final approval and issuance of loan guarantees by the Department of Energy are subject to negotiation of definitive agreements, completion of due diligence by the Department of Energy and satisfaction of other conditions. Therefore, there can be no assurance that the Department of Energy will ultimately issue, or that we or the other Co-owners will accept, the loan guarantees. We expect that we will fund any Vogtle costs not funded under the Department of Energy loan guarantee program through capital market financings. The conditional commitment will expire on June 30, 2013, unless further extended by the Department of Energy.

Bond Financings. In November 2012, we issued $250 million of fixed rate first mortgage bonds, including $211 million as long-term financing for costs related to Vogtle Units No. 3 and No. 4 and $39 million to fund the portion of the acquisition cost of Smith that the Rural Utilities Service is not financing. To-date we have issued $1.36 billion of first mortgage bonds to fund the development and construction of the additional units at Plant Vogtle.

Instead of remarketing the $212.8 million of pollution control revenue bonds, that were originally issued on our behalf by the Development Authorities of Appling, Burke and Monroe Counties, and were subject to mandatory tender on March 1, 2013, we elected to refund the bonds with commercial paper. In April 2013, we plan to refund the commercial paper through an issuance of $212.8 million of pollution control revenue bonds by the development authorities on our behalf.

Capital Requirements

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 2013 through 2015. 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)

	2013	2014	2015	Total
Future Generation(2)	$ 458	$ 644	$ 539	$ 1,641
Existing Generation(3)	106	137	128	371
Environmental Compliance(4)	88	30	2	120
Nuclear Fuel(5)	108	127	103	338
General Plant	3	3	1	7
Total	$ 763	$ 941	$ 773	$ 2,477

(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.
(3) Normal additions and replacements to plant in-service
(4) Pollution control equipment being installed at coal-fired Plants Scherer and Wansley.
(5) Includes nuclear fuel on existing nuclear units and initial nuclear fuel core for Vogtle Units No. 3 and No. 4.

In addition to the amounts reflected in the table above, we expect to incur capitalized costs of $985 million to complete construction of Vogtle Units No. 3 and No. 4. For information about steps we have taken to procure financing for this project, see "– *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 national level, particularly in relation to climate change, we cannot predict what capital costs may ultimately be required.

Environmental compliance projects currently underway include the installation of flue gas desulfurization equipment and a selective catalytic reduction system at Plant Scherer and some mercury controls at Plant Wansley, all expected to be in service by the end of 2014.

Depending on how we and the other co-owners of Plants Wansley and 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."

Contractual Obligations. The table below reflects, as of December 31, 2012, our contractual obligations for the periods indicated.

Contractual Obligations
(dollars in millions)

	2013	2014-2015	2016-2017	Beyond 2017	Total
Long-Term Debt:					
Principal[1]	$ 143	$ 693	$ 236	$ 4,859	$ 5,931
Interest[2]	280	536	532	3,755	5,103
Capital Leases[3]	36	61	30	160	287
Operating Leases	6	10	9	7	32
Rocky Mtn.Lease Transaction[4]	–	–	–	38	38
Chattahoochee O&M Agmts.	22	47	47	22	138
Asset Retirement Obligations[5]	–	3	5	2,428	2,436
Purchase Commitments[6]	176	182	95	201	654
Total	**$ 663**	**$ 1,532**	**$ 954**	**$ 11,470**	**$ 14,619**

(1) Includes principal amounts that would be due if the credit support facilities for the 2009 and 2010 pollution control bonds were drawn upon and became payable in accordance with their terms, equal to $37 million in 2013, $37 million in 2014, and $171 million in 2015. To date, none of the credit support facilities backing the Series 2009 and 2010 bonds have been drawn upon for principal and we anticipate extending these facilities before their expiration. The nominal maturities of the 2009 and 2010 pollution control bonds range from 2030 through 2038.

(2) Includes interest expense related to variable rate debt. Future variable rates are based on projected LIBOR and SIFMA interest rate curves as of February 2013.

(3) Amounts represent total rental payment obligations, not amortization of debt underlying the leases.

(4) We have entered into an Equity Funding Agreement for a third party to fund this obligation. For additional information, see "– *Off-Balance Sheet Arrangements-Rocky Mountain Lease Arrangement.*"

(5) A substantial portion of this amount relates to the decommissioning of nuclear facilities.

(6) Includes commitments for the procurement of coal and nuclear fuel and natural gas related transportation agreements. Contracts for coal and nuclear fuel procurement, in most cases, contain provision for price escalations, minimum purchase levels and other financial commitments.

Inflation

As with utilities generally, inflation has the effect of increasing the cost of our operations and construction program. Operating and construction costs have been less affected by inflation over the last few years because rates of inflation have been relatively low. While we cannot predict what level of inflation may occur in the future, in light of current U.S. financial policies, the potential for inflationary pressures exist.

Credit Rating Risk

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

Our Ratings	S&P	Moody's	Fitch
Long-term ratings:			
Senior secured rating[1]	A	Baa1	A
Issuer rating	A	Baa2	n/r[2]
Rating outlook	Stable	Stable	Stable
Short-term rating:			
Commercial paper rating	A-1	P-2	F1

(1) We currently have no unsecured ratings assigned to any of our long-term debt.

(2) n/r indicates no rating assigned for this rating category

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, 2012, our maximum potential collateral requirements were as follows:

At senior secured rating levels:

- a total of approximately $50 million at a senior secured level of BBB-/Baa3,
- a total of approximately $183 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured or issuer rating levels:

- a total of approximately $742,000 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 our pollution control bond agreements contain provisions based on the ratings assigned to the bonds (which could be related to either our rating or a bond insurer's rating if the bonds are insured) that, upon a credit rating downgrade below specified levels, could result in increased interest rates. Also, borrowing rates and commitment fees in all of our line 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 credit ratings below the rating triggers contained in any of our financial and contractual agreements. 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.

Off-Balance Sheet Arrangements

We are liable for certain contractual obligations for which another party is primarily liable, and we would be expected to pay only if the other party fails to satisfy such obligations. Currently, our only off-balance sheet obligations are in connection with the Rocky Mountain lease arrangement; however, as a result of the lease terminations described below, these obligations are not material.

Rocky Mountain Lease Arrangements. 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 five leases were each owned by separate owner trusts for the benefit of two of the owner participants, and represented approximately 90% of the six original lease transactions. As a result, only one of the original lease arrangements, approximately 10% of the original lease transactions, remains in place. The termination of these five leases significantly reduced our exposure to the credit counterparties participating in the leases. Our negotiated cost to terminate the five leases represented a substantial discount to the amount that would otherwise be due pursuant to the contractual provisions for an early termination event under the lease documents. These lease transactions, and the subsequent terminations thereof, had substantially no effect on our ownership, possession or use of Rocky Mountain. See Note 4 of Notes to Consolidated Financial Statements for additional information regarding these terminations.

If at any point during the term of the remaining lease the owner participant is willing to terminate the lease on terms acceptable to us, we would terminate this lease transaction. If the remaining lease transaction runs through its base term, we will exercise one of our options under the lease documents. One of these options is to cause RMLC to purchase the owner trust's undivided interest in Rocky Mountain at a fixed purchase price with funds that were set aside at the beginning of the lease term and designed to match the fixed purchase price at the end of the lease term.

The assets of RMLC are not available to pay our creditors or our affiliates', other than RMLC, creditors.

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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in July 2010 could impact our use of over-the-counter derivatives. As a commercial end-user, we are exempt from certain provisions of the Dodd-Frank Act and we expect our cooperative status to exempt us from certain additional requirements. However, we will be subject to regulations that could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect the availability and cost of over-the-counter derivatives. The full and final impact and cost of the Dodd-Frank Act, which we do not expect to be significant, cannot be determined until all regulations are finalized.

For additional information regarding our rate structure, see "BUSINESS – OGLETHORPE POWER CORPORATION – Electric Rates."

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 and external 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

At December 31, 2012, we were exposed to the risk of changes in interest rates related to our $1.4 billion of variable rate debt, which includes $570 million of commercial paper outstanding (which typically has maturities of between 1 and 90 days), a $260 million bank term loan and $581 million of pollution control bond debt outstanding (including weekly rate bonds, auction rate securities subject to repricing every 35 days and term rate bonds which we subsequently refunded on March 1, 2013 on an interim basis using commercial paper, and which we plan to refund in April 2013 with term rate pollution control bonds). At December 31, 2012, the weighted average interest rate on this variable rate debt was 0.85%. If, during 2013, 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 $14 million.

Our objective in managing interest rate risk is to maintain a balance of fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. As part of this debt management strategy we have a general guideline of having between 15% and 30% variable rate debt to total debt. At December 31, 2012, we had 22% of our total debt, including commercial paper and capital lease debt, in a variable rate mode.

The operative documents underlying the pollution control bond debt contain provisions that allow us to convert the debt 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. To mitigate the risk of rising interest rates, in the fourth quarter of 2011, we hedged a portion of our interest rate risk related to the financing of the new Vogtle units. Under this program, we made upfront premium payments of $100 million to purchase interest rate options to hedge the interest rates on approximately $2.2 billion of debt that will be used to finance the new Vogtle units.

The interest rate options we purchased, commonly known as LIBOR swaptions, give us the future right, but not the obligation, to enter into a swap in which we would pay a fixed rate and receive a floating LIBOR rate. However, the swaptions are required to be cash settled based on their value on the expiration date before any payments on the underlying swap are actually made. As a result, the swaptions effectively cap our interest rates by offsetting the present value cost of an increase in interest rates above the fixed rate. The cash settlement value depends on the extent to which prevailing LIBOR swap rates exceed the fixed rate on the underlying swap, and the value would be zero if swap rates are at or below the fixed rate upon expiration. The fixed rates on the LIBOR swaptions we purchased are in the range of 150 to 200 basis points above LIBOR swap rates in effect as of December 31, 2012 and the weighted average fixed rate is 4.17%. The swaptions' expiration dates are timed to match the borrowing schedule for the new Vogtle units that was in place when we implemented this hedging program and the swaptions are designed to hedge the interest rates for a portion of these borrowings from 2013 through 2017.

We paid the entire premium at the time we entered into these swaption transactions and have no additional payment obligations. However, upon expiration of the swaptions, each counterparty will be obligated to pay us the cash value of the swaption, if any. In order to diversify counterparty risk, we entered into these transactions with six large banks with average ratings ranging from A- to AA. To manage our credit exposure to these counterparties, the agreements we have with the counterparties contain support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the swaptions outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from $0 to $10 million depending on each counterparty's credit rating.

We expect to defer any gains or losses from the change in fair value of each swaption and related carrying and other incidental costs. The deferred costs, which are not expected to exceed $135 million, and deferred gains, if any, from the sale or settlement of the swaptions will then be amortized and collected in rates over the life of the $2.2 billion of debt that we hedged with the swaptions.

Capital Leases

We entered into a power purchase and sale agreement with Doyle I, LLC to purchase all of the output from a five-unit gas-fired generation facility. The Doyle agreement is reported on our balance sheet as a capital lease. The lease payments vary to the extent the interest rate on the lessor's debt varies from 6.00%. At December 31, 2012, the weighted average interest rate on the lease obligation was 5.90%.

Equity Price Risk

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 (see Note 1 of Notes to Consolidated Financial Statements). 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.

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.

A 10% decline in the value of the internal and external funds' equity securities as of December 31, 2012 would result in a loss of value to the funds of approximately $19 million. For further discussion on our nuclear decommissioning trust funds, see Note 1 of Notes to Consolidated Financial Statements.

Commodity Price Risk

Coal

We are also exposed to the risk of changing prices for fuels, including coal and natural gas. We have interests in 1,501 megawatts of coal-fired nameplate capacity at Plants Scherer and Wansley. 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. We anticipate that our existing contracts and stockpiles will provide fixed prices for 100% of our remaining 2013 forecasted coal requirements at Plants Scherer and Wansley, respectively, and 72% and 100% of our forecasted 2014 coal requirements at Plants Scherer and Wansley, respectively.

The objective of our coal procurement strategy is to ensure reliable coal supply and some price stability for our members. Our strategy focuses on 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, lease or operate eight gas fired generation facilities totaling 4,170 megawatts of nameplate capacity. See "PROPERTIES – Generating Facilities" and "BUSINESS – OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Smarr EMC*."

We manage exposure to fluctuations in the market price of natural gas for approximately 15 of our members who have elected to participate in our natural gas hedging program. This program layers in fixed prices over a rolling eight-quarter time horizon using natural gas swap arrangements for a portion of the forecasted gas requirements related to the gas-fired resources that we manage and/or operate. We also use natural gas swap arrangements to hedge natural gas requirements associated with short-term electricity sales into the wholesale market. Under these 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. If the natural gas swaps had been terminated on December 31, 2012, we would have made a net payment of approximately $1.1 million. As of December 31, 2012, approximately 8% of our 2013 total system forecasted natural gas requirements (including requirements for the Smarr facilities) were hedged under swap arrangements. A hypothetical 10% decline in the market price of natural gas would have resulted in a decrease of approximately $1.9 million to the fair value of our natural gas swap agreements. Effective April 1 of each year, additional members may elect to participate in our natural gas hedging program. Members may choose to discontinue receiving these natural gas price management services at any time.

Changes in Risk Exposure

Our exposure to changes in interest rates, the price of equity securities 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

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OGLETHORPE POWER CORPORATION

CONSOLIDATED STATEMENTS OF REVENUES AND EXPENSES

For the years ended December 31, 2012, 2011 and 2010

	(dollars in thousands)		
	2012	2011	2010
Operating revenues:			
Sales to Members	**$ 1,204,008**	$ 1,224,238	$ 1,292,667
Sales to non-Members	**120,102**	166,040	1,478
Total operating revenues	**1,324,110**	1,390,278	1,294,145
Operating expenses:			
Fuel	**516,223**	531,147	501,113
Production	**371,909**	357,069	332,236
Depreciation and amortization	**160,849**	199,040	131,491
Purchased power	**50,022**	56,634	59,076
Accretion	**19,554**	18,249	17,131
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(16,280)**	(9,681)	13,849
Total operating expenses	**1,102,277**	1,152,458	1,054,896
Operating margin	**221,833**	237,820	239,249
Other income:			
Investment income	**28,684**	29,496	30,208
Gain on termination of Rocky Mountain transactions	**18,976**	–	–
Amoritization of deferred gains	**4,535**	5,660	5,660
Allowance for equity funds used during construction	**2,879**	2,904	2,417
Other	**6,413**	6,204	5,366
Total other income	**61,487**	44,264	43,651
Interest charges:			
Interest expense	**307,482**	296,138	266,641
Allowance for debt funds used during construction	**(83,892)**	(72,692)	(41,593)
Amortization of debt discount and expense	**20,410**	20,901	24,119
Net interest charges	**244,000**	244,347	249,167
Net margin	**$ 39,320**	$ 37,737	$ 33,733

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE MARGIN
For the years ended December 31, 2012, 2011, 2010

	(dollars in thousands)		
	2012	2011	2010
Net Margin	**$ 39,320**	$ 37,737	$ 33,733
Other comprehensive margin:			
Unrealized gain on available-for-sale securities	**285**	1,087	784
Total comprehensive margin	**$ 39,605**	$ 38,824	$ 34,517

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2012 and 2011

	(dollars in thousands)	
	2012	2011
Assets		
Electric plant:		
In service	**$ 7,506,707**	$ 7,335,866
Less: Accumulated provision for depreciation	**(3,472,087)**	(3,328,585)
	4,034,620	4,007,281
Nuclear fuel, at amortized cost	**321,196**	284,205
Construction work in progress	**2,240,920**	1,784,264
Total electric plant	**6,596,736**	6,075,750
Investments and funds:		
Nuclear decommissioning trust fund	**300,785**	268,597
Deposit on Rocky Mountain transactions	**14,392**	132,048
Investment in associated companies	**60,770**	57,626
Long-term investments	**77,022**	80,055
Restricted cash	**8,953**	43,070
Other, at cost	**1,084**	3,564
Total investments and funds	**463,006**	584,960
Current assets:		
Cash and cash equivalents	**298,565**	443,671
Restricted short-term investments	**64,671**	106,676
Receivables	**134,896**	124,650
Inventories, at average cost	**263,949**	246,795
Prepayments and other current assets	**16,073**	16,175
Total current assets	**778,154**	937,967
Deferred charges and other assets:		
Deferred debt expense, being amortized	**63,210**	67,470
Regulatory assets	**352,902**	351,547
Other	**60,558**	61,135
Total deferred charges	**476,670**	480,152
Total assets	**$ 8,314,566**	$ 8,078,829

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2012 and 2011

	(dollars in thousands)	
	2012	2011
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 673,009**	$ 633,689
Accumulated other comprehensive margin	**903**	618
	673,912	634,307
Long-term debt	**5,784,130**	5,562,925
Obligations under capital leases	**135,943**	146,781
Obligation under Rocky Mountain transactions	**14,392**	132,048
Total capitalization	**6,608,377**	6,476,061
Current liabilities:		
Long-term debt and capital leases due within one year	**168,393**	172,818
Short-term borrowings	**569,480**	461,093
Accounts payable	**145,451**	134,095
Accrued interest	**58,649**	91,106
Accrued and withheld taxes	**4,881**	21,118
Members power bill prepayments, current	**65,079**	66,819
Other current liabilities	**19,539**	25,080
Total current liabilities	**1,031,472**	972,129
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**23,638**	26,113
Asset retirement obligations	**381,362**	298,758
Member power bill prepayments, non-current	**40,853**	35,500
Power sale agreement, being amortized	**40,355**	54,816
Regulatory liabilities	**129,985**	164,000
Other	**58,524**	51,452
Total deferred credits and other liabilities	**674,717**	630,639
Total equity and liabilities	**$ 8,314,566**	$ 8,078,829

Commitments and Contingencies (Notes 1, 9, 11 and 13)

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2012 and 2011

	(dollars in thousands) 2012	2011
Long-term debt:		
Mortgage notes payable to the Federal Financing Bank at interest rates varying from 2.20% to 8.43% (average rate of 4.86% at December 31, 2012) due in quarterly installments through 2043	**$ 2,115,640**	$ 2,125,149
Mortgage notes payable to National Rural Utilities Cooperative Finance Corporation at interest rates varying from 3.25% to 4.90% (average rate of 4.19% at December 31, 2012) due in quarterly installments through 2020	**6,659**	7,388
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 2009A		
First Mortgage Bonds, 6.10%, due 2019	**350,000**	350,000
• Series 2009B		
First Mortgage Bonds, 5.95%, due 2039	**400,000**	400,000
• Series 2009		
Clean renewable energy bond, 1.81%, due 2024	**12,124**	13,134
• 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**	–
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 1992A Monroe		
Serial bonds, fully redeemed January 2012	**–**	10,371
• Series 2003A Burke, Heard, Monroe and 2003B Burke		
Auction rate bonds, 0.32%, due 2024	**95,230**	95,230
• Series 2004 Burke and Monroe		
Auction rate bonds, 0.32%, due 2020	**11,525**	11,525
• Series 2005 Burke and Monroe		
Auction rate bonds, 0.32%, due 2040	**15,865**	15,865
• Series 2008A through 2008C Burke		
Fixed rate bonds, 5.30% to 5.70%, due 2032 through 2043	**255,035**	255,035
• Series 2008E Burke		
Fixed rate bonds, 7.00%, due 2020 through 2023	**144,750**	144,750
• Series 2008G Burke		
Term rate bonds, 0.90% through February 28, 2013, due 2039	**22,325**	22,325
• Series 2009A Heard and Monroe, and 2009B Monroe		
Weekly rate bonds, 0.15%, due 2030 through 2038	**112,055**	112,055
• Series 2010A Burke and Monroe, and 2010B Burke		
Weekly rate bonds, 0.13% to 0.15%, due 2036 through 2037	**133,550**	133,550
• Series 2011A Appling, Burke and Monroe		
Term rate bonds, 2.50% through February 28, 2013, due 2038 through 2040	**180,380**	180,380
• Series 2012A Monroe		
Term rate bonds, 0.90% through February 28, 2013, due 2039	**10,055**	–
CoBank, ACB notes payable:		
• Transmission mortgage notes payable: variable at 2.09% to 3.25% through January 30, 2013, due in bimonthly installments through September 1, 2019	**5,256**	5,746
Total Secured Long-term, net	**$ 5,670,449**	$ 5,432,503
Unsecured bank term loans:		
Notes payable: variable at 1.46% through January 8, 2013, due April 2014	**260,000**	260,000
Total long-term debt	**$ 5,930,449**	$ 5,692,503
Obligations under capital leases	**161,249**	191,900
Obligation under Rocky Mountain transactions	**14,392**	132,048
Patronage capital and membership fees	**673,009**	633,689
Accumulated other comprehensive margin	**903**	618
Subtotal	**6,780,002**	6,650,758
Less: long-term debt and capital leases due within one year	**(168,393)**	(172,818)
Less: unamortized bond discounts on long-term debt	**(3,232)**	(1,879)
Total capitalization	**$ 6,608,377**	$ 6,476,061

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, 2012, 2011 and 2010

	2012	2011	2010
		(dollars in thousands)	
Cash flows from operating activities:			
Net margin	**$ 39,320**	$ 37,737	$ 33,733
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	**301,442**	321,715	250,723
Accretion cost	**19,554**	18,249	17,131
Amortization of deferred gains	**(45,952)**	(5,660)	(5,660)
Allowance for equity funds used during construction	**(2,879)**	(2,904)	(2,417)
Deferred outage costs	**(26,392)**	(56,358)	(25,911)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(16,280)**	(9,681)	13,849
Gain on sale of investments	**(10,784)**	(14,915)	(14,239)
Regulatory deferral of costs associated with nuclear decommissioning	**(710)**	5,089	5,480
Other	**(7,786)**	(10,598)	(9,022)
Change in operating assets and liabilities:			
Receivables	**(17,465)**	(8,456)	(7,299)
Inventories	**(17,154)**	(40,774)	38,022
Prepayments and other current assets	**(355)**	(2,146)	(4,023)
Accounts payable	**(12,714)**	8,617	(729)
Accrued interest	**(32,457)**	14,671	25,488
Accrued and withheld taxes	**(16,237)**	(6,362)	2,307
Other current liabilities	**(412)**	542	791
Member power bill prepayments	**3,613**	(10,177)	(88,018)
Total adjustments	**117,032**	200,852	196,473
Net cash provided by operating activities	**156,352**	238,589	230,206
Cash flows from investing activities:			
Property additions	**(646,486)**	(839,503)	(669,206)
Plant acquisitions	**–**	(530,293)	–
Activity in nuclear decommissioning trust fund – Purchases	**(657,638)**	(1,068,979)	(608,542)
– Proceeds	**651,709**	1,063,277	603,600
Activity in bond, reserve and construction funds – Purchases	**2,719**	–	–
Decrease (increase) in restricted cash and cash equivalents	**34,574**	(37,383)	16,105
Decrease (increase) in restricted short-term investments	**42,005**	(9,390)	(16,696)
Activity in other long-term investments – Purchases	**(6,278)**	(2,469)	(6,822)
– Proceeds	**14,772**	1,100	18,524
Activity on interest rate options – Purchases / Collateral returned	**(208,850)**	(100,000)	–
– Collateral received	**174,730**	43,070	–
Other	**(19,055)**	(10,254)	2,822
Net cash used in investing activities	**(617,798)**	(1,490,824)	(660,215)
Cash flows from financing activities:			
Long-term debt proceeds	**366,008**	1,163,593	740,124
Long-term debt payments	**(164,938)**	(288,722)	(240,185)
Increase in short-term borrowings	**108,386**	155,135	22,325
Other	**6,884**	(6,312)	888
Net cash provided by financing activities	**316,340**	1,023,694	523,152
Net (decrease) increase in cash and cash equivalents	**(145,106)**	(228,541)	93,143
Cash and cash equivalents at beginning of period	**443,671**	672,212	579,069
Cash and cash equivalents at end of period	**$ 298,565**	$ 443,671	$ 672,212
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	**$ 246,705**	$ 196,629	$ 187,958
Supplemental disclosure of non-cash investing and financing activities:			
Change in plant expenditures included in accounts payable	**$ 32,657**	$ (7,848)	$ 138,898

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

OGLETHORPE POWER CORPORATION

CONSOLIDATED STATEMENTS OF PATRONAGE CAPITAL AND MEMBERSHIP FEES AND ACCUMULATED OTHER COMPREHENSIVE MARGIN (DEFICIT)

For the years ended December 31, 2012, 2011 and 2010

	(dollars in thousands)		
	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Margin (Deficit)	Total
Balance at December 31, 2009	$ 562,219	$ (1,253)	$ 560,966
Components of comprehensive margin in 2010			
Net margin	33,733	–	33,733
Unrealized gain on available-for-sale securities	–	784	784
Total comprehensive margin			34,517
Balance at December 31, 2010	595,952	(469)	595,483
Components of comprehensive margin in 2011			
Net margin	37,737	–	37,737
Unrealized gain on available-for-sale securities	–	1,087	1,087
Total comprehensive margin			38,824
Balance at December 31, 2011	633,689	618	634,307
Components of comprehensive margin in 2012			
Net margin	39,320	–	39,320
Unrealized gain on available-for-sale securities	–	285	285
Total comprehensive margin			39,605
Balance at December 31, 2012	$ 673,009	$ 903	$ 673,912

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

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, GA that operates on a not-for-profit basis. We are owned by 38 retail electric distribution cooperative members in Georgia. The wholesale electric power we provide consists of a combination of generating units totaling 6,844 megawatts of nameplate capacity. Our members in turn distribute energy on a retail basis to approximately 4.1 million people.

b. Basis of accounting

Our consolidated financial statements include our accounts and the accounts of our majority-owned and controlled subsidiaries. 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.

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, 2012 and 2011 and the reported amounts of revenues and expenses for each of the three years in the period ended December 31, 2012. 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 $195 in membership fees. Patronage capital includes retained net margin. Any excess of revenue over expenditures from operations is treated as advances of capital by our members and is allocated to each of them on the basis of their fixed percentage capacity cost responsibilities in our generation and purchased power resources.

Any distributions of patronage capital are subject to the discretion of our board of directors, subject to first mortgage indenture requirements. Under the 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. Accumulated comprehensive margin (deficit)

The table below provides detail regarding the beginning and ending balance for each classification of other comprehensive margin (deficit) along with the amount of any reclassification adjustments included in net margin for each of the years presented in the Statement of Patronage Capital and Membership Fees and Accumulated Other Comprehensive Margin (Deficit). Our effective tax rate is zero; therefore, all amounts below are presented net of tax.

Accumulated Other Comprehensive Margin (Deficit)

	(dollars in thousands) Available-for-sale Securities
Balance at December 31, 2009	$ (1,253)
Unrealized gain	784
Balance at December 31, 2010	(469)
Unrealized gain	1,087
Balance at December 31, 2011	618
Unrealized gain	285
Balance at December 31, 2012	**$ 903**

e. Margin policy

We are required under the first mortgage indenture to produce a margins for interest ratio of at least 1.10 for each fiscal year. For the years 2012, 2011 and 2010, we achieved a margins for interest ratio of 1.14.

f. Operating revenues

Operating revenues from sales to members consist primarily of electricity sales pursuant to long-term wholesale power contracts which we maintain with each of our members. These wholesale power contracts obligate each member to pay us for capacity and energy furnished in accordance with rates we establish. Electricity revenues are recognized when capacity and energy are provided. Energy provided is determined based on meter readings which are conducted at the end of each month. Actual energy costs are compared, on a monthly basis, to the billed energy costs, and an adjustment to revenues is made such that energy revenues are equal to actual energy costs.

Operating revenues from sales to non-members consists of capacity and energy sales to Georgia Power Company, as well as energy sales to other non-members. These capacity and energy sales are primarily associated with the Thomas A. Smith Energy Facility, formerly known as the Murray Energy Facility, which we acquired in April 2011. The agreement with Georgia Power, which was for the sale of the entire output of Unit No. 1 of Smith, expired on May 31, 2012. For further discussion of the Smith acquisition, see Note 14.

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2012, 2011 and 2010:

	2012	2011	2010
Cobb EMC	**12.8%**	12.5%	14.5%
Jackson EMC	**11.9%**	10.9%	11.6%
Sawnee EMC(1)	**n/a**	n/a	10.6%

(1) In 2012 and 2011, Sawnee accounted for less than 10% of our total operating revenues.

In 2011, the Rural Utilities Service approved a rate change that permitted us to implement two rate management programs that allow us to expense and recover certain costs on a current basis that would otherwise be capitalized. The subscribing members of Smith and/or Vogtle Units No. 3 and No. 4, can elect to participate in one, both or neither of these two plans on an annual basis. The Smith program allows for the accelerated recovery of deferred net costs related to Smith. The Smith program became effective December 31, 2011. The Vogtle program allows for the recovery of financing costs associated with the construction of Vogtle Units No. 3 and No. 4 on a current basis. This program became effective January 1, 2012. Under these programs, amounts billed to our members in 2011 and 2012 were $5,436,000 and $26,149,000, respectively.

g. Receivables

A substantial portion of our receivables are related to electricity sales to our members. 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. Member receivables at December 31, 2012 and 2011 were $109,673,000 and $108,920,000, respectively. The remainder of our receivables is primarily related to transactions with affiliated companies, electricity sales to non-members and to interest income on investments. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible.

h. Nuclear fuel cost

The cost of nuclear fuel, including a provision for the disposal of spent fuel, is being amortized to fuel expense based on usage. The total nuclear fuel expense for 2012, 2011 and 2010 amounted to $81,723,000, $74,814,000, and $65,916,000, respectively.

Contracts with the U.S. Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at 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.

On April 5, 2012, the U.S. Court of Federal Claims issued a final order for judgment in favor of Georgia Power in a lawsuit seeking damages for nuclear fuel spent storage costs incurred at Plant Hatch and Plant Vogtle Units No. 1 and No. 2 from 1998 through 2004. Our ownership share of the $54,017,000 total award was $16,205,000. The judgment was recorded in June 2012 and resulted in a $9,679,000 reduction in total operating expenses and a $6,526,000 reduction to plant in service.

In a second claim filed in 2008 against the Department of Energy by Georgia Power as agent for the co-owners, damages for nuclear fuel spent storage costs at Hatch and Vogtle Units No. 1 and No. 2 are being sought for the period of January 2005 through December 2010. No amounts have been recognized in the financial statements as of December 31, 2012 for the second claim. The final outcome of this matter cannot be determined at this time.

An on-site dry storage facility for Hatch is operational and can be expanded to accommodate spent fuel through the life of the plant. Sufficient storage capacity is available at Plant Vogtle in the spent fuel pools to maintain full core discharge capacity for both units into 2014. Construction of an on-site dry storage facility at Vogtle Units No.1 and No. 2 has commenced to ensure that we maintain spent fuel pool full-core discharge capability beyond 2014.

i. Asset retirement obligations and other retirement costs

Asset retirement obligations are computed as the present value of the costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The liability we recognized primarily relates to decommissioning at our nuclear facilities. In addition, we have retirement obligations related to ash ponds, landfill sites and asbestos removal.

Under the accounting provisions for regulated operations, we record an offsetting regulatory asset or liability to reflect the difference in timing of recognition of the costs of decommissioning for financial statement purposes and for ratemaking purposes. We estimate an annual increase of approximately $200,000 over the next several years to the regulatory asset. For information regarding the regulatory asset for asset retirement obligations, see Note 1s.

In December 2012, we obtained revised asset retirement obligation studies associated with nuclear decommissioning at Hatch Unit No. 1 and No. 2, Vogtle Unit No. 1 and No. 2 and the decommissioning of ash ponds at Plants Scherer and Wansley. The change in cash flow estimates for both nuclear and ash pond decommissioning are reflected in the table below. For information regarding 2012 site studies associated with nuclear decommissioning, see Note 1j.

The following tables reflect the details of the Asset Retirement Obligations included in the balance sheets for the years 2012 and 2011.

(dollars in thousands)	**2012**	2011
Balance at beginning of year	**$ 298,758**	$ 280,496
Liabilities incurred	**1,632**	423
Liabilities settled	**(1,117)**	(410)
Accretion	**19,554**	18,249
Change in Cash Flow Estimate	**62,535**	–
Balance at end of year	**$ 381,362**	$ 298,758

Accounting standards for asset retirement and environmental obligations does not permit non-regulated entities to accrue future retirement costs associated with long-lived assets for which there are no legal obligations to retire. In accordance with regulatory treatment of these costs, we continue to recognize the retirement costs for these other obligations in depreciation rates. For information regarding accumulated retirement costs for other obligations, see Note 1s.

j. Nuclear decommissioning trust fund

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. We have established external trust funds to comply with the NRC's regulations. The funds set aside for decommissioning 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. The funds are invested in a diversified mix of equity and fixed income securities. We have limited oversight of the day-to-day management of the fund investments.

We record the investment securities held in the nuclear decommissioning trust fund, which are classified as available-for-sale, 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. Unrealized gains and losses of the nuclear decommissioning trust fund that would be recorded in earnings or other comprehensive margin (deficit) by a non-regulated entity are directly deducted from or added to the regulatory asset for asset retirement obligations in accordance with our rate-making treatment. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset.

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. Actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in regulatory requirements, changes in technology, and changes in costs of labor, materials and equipment. The estimated costs of decommissioning are based on the most current study performed in 2012. Our portion of the estimated costs of decommissioning co-owned nuclear facilities were as follows:

	(dollars in thousands)			
2012 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 2012 dollars	$ 186,000	$ 252,000	$ 182,000	$ 241,000

We have not collected any provision for decommissioning during the years 2012, 2011 and 2010 because the balance in the decommissioning trust fund is expected to be sufficient to fund the nuclear decommissioning obligation in future years. In projecting future costs, the escalation rate for labor, materials and equipment was assumed to be 2.4%. We assume a 6.0% earnings rate for our decommissioning trust fund assets. Since inception (1990) to 2012, the nuclear decommissioning trust fund has produced an average annualized return of approximately 7.1%. Notwithstanding the results of the revised site studies, our management believes that any increase in cost estimates of decommissioning can be recovered in future rates.

k. Depreciation

Depreciation is computed on additions when they are placed in service using the composite straight-line method. The depreciation rates for steam and nuclear below reflect revised rates from 2011 depreciation rate studies. Annual depreciation rates, as approved by the Rural Utilities Service, in effect in 2012, 2011 and 2010 were as follows:

	Range of Useful Life in years*	**2012**	2011	2010
Steam production	49-65	**1.85%**	1.88%	1.56%
Nuclear production	37-60	**1.54%**	1.45%	1.50%
Hydro production	50	**2.00%**	2.00%	2.00%
Other production	27-33	**2.74%**	2.74%	2.60%
Transmission	36	**2.75%**	2.75%	2.75%
General	3-50	**2.00-33.33%**	2.00-33.33%	2.00-33.33%

* Calculated based on the composite depreciation rates in effect for 2012.

Depreciation expense for the years 2012, 2011 and 2010 was $164,901,000, $165,603,000, and $161,395,000, respectively.

l. Electric plant

Electric plant is stated at original cost, which is the cost of the plant when first dedicated to public service, 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 ended 2012, 2011 and 2010, the allowance for funds used during construction rates were 5.12%, 5.55% and 5.73%, respectively.

Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are charged to expense. Replacements and renewals of items considered to be units of property are charged to the plant accounts. At the time properties are disposed of, the original cost, plus cost of removal, less salvage of such property, is charged to the accumulated provision for depreciation.

m. 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 of more than three months are classified as other short-term investments.

n. Restricted cash

At December 31, 2012, we had restricted cash totaling $9,109,000 of which $8,953,000 was classified as long-term. The long-term restricted cash balance at December 31, 2012 consisted of funds posted as collateral by counterparties to our interest rate options. See Note 3 for a discussion of our interest rate options.

o. Restricted short-term investments

At December 31, 2012 and 2011, we had $64,671,000 and $106,676,000, respectively, on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted funds can only be utilized for future Rural Utilities Service/Federal Financing Bank debt service payments. The deposit earns interest at a Rural Utilities Service guaranteed rate of 5% per annum.

p. Inventories

We maintain inventories of fossil fuels and spare parts for our generation plants. These inventories are stated at weighted average cost on the accompanying balance sheets.

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 based on weighted average cost. The spare parts inventories primarily include the direct cost of generating plant spare parts. Spare parts are charged to inventory when purchased and then expensed or capitalized, as appropriate, when installed. The spare parts inventory is carried at weighted average cost and the parts are charged to expense or capital at weighted average cost.

At December 31, 2012 and 2011, fossil fuels inventories were $94,491,000 and $94,872,000, respectively. Inventories for spare parts at December 31, 2012 and 2011 were $169,458,000 and $151,923,000, respectively.

q. Deferred charges and other assets

We account for debt issuance costs as deferred debt expense. Deferred debt expense is amortized to expense on a straight-line basis over the life of the respective debt issues, which approximates the effective interest rate method. As of December 31, 2012, the remaining amortization periods for debt issuance costs range from approximately 1 to 38 years.

r. 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 and are recorded as a reduction to member revenues. At December 31, 2012, member power bill prepayments as reflected on the consolidated balance sheets, including unpaid discounts, were $105,932,000, of which, $65,079,000 is classified as a current liability and $40,853,000 as deferred credits and other liabilities. The prepayments are being applied against members' power bills through November 2017, with the majority of the remaining balance scheduled to be applied by the end of 2013.

We have recorded a liability for a power sale agreement assumed in conjunction with the Hawk Road acquisition in May 2009. The liability is being amortized over the remaining life of the agreement which ends in 2015.

s. 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 under the wholesale power contracts with our members extending 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.

The following regulatory assets and (liabilities) are reflected on the accompanying balance sheets as of December 31, 2012 and 2011:

	(dollars in thousands) 2012	2011
Regulatory Assets:		
Premium and loss on reacquired debt	**$ 86,319**	$ 98,538(a)
Amortization on capital leases	**28,670**	46,627(b)
Outage costs	**30,901**	42,866(c)
Interest rate swap termination fees	**17,326**	21,316(d)
Asset retirement obligations	**11,382**	29,341(e)
Depreciation expense	**49,785**	51,209(f)
Vogtle Units No. 3 and No. 4 training costs	**23,030**	17,602(g)
Interest rate options cost	**75,716**	30,735(h)
Effects on net margin- Smith Energy Facility	**21,394**	3,536(i)
Other regulatory assets	**8,379**	9,777(j)
Total Regulatory Assets	**$ 352,902**	$ 351,547
Regulatory Liabilities:		
Accumulated retirement costs for other obligations	**$ 28,846**	$ 32,687(e)
Net benefit of Rocky Mountain transactions	**4,303**	47,783(k)
Effects on net margin- Hawk Road Energy Facility	**17,113**	15,811(i)
Major maintenance sinking fund	**30,948**	28,524(l)
Debt service adder	**47,486**	37,586(m)
Other regulatory liabilities	**1,289**	1,609(j)
Total Regulatory Liabilities	**$ 129,985**	$ 164,000
Net regulatory assets	**$ 222,917**	$ 187,547

(a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt amortized over the period of the refunding debt, which range up to 30 years.

(b) See Note 6 under "Capital Leases." Recovered over the remaining life of the leases through 2031.

(c) Consists of both coal-fired and nuclear refueling outage costs. Coal-fired outage costs are amortized on a straight-line basis to expense over an 18 to 36-month period. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 to 24-month operating cycles of each unit.

(d) Represents amount paid on settled interest rate swaps arrangements that are being amortized through 2016 and 2019.

(e) See Note 1i under "Asset retirement obligations" for a discussion of the asset retirement obligation deferral and recovery and retirement costs for other obligations.

(f) Prior to 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.

(g) Deferred charges related to Vogtle Units No. 3 and No. 4 training and interest related carrying costs of such training. Amortization will commence effective with the commercial operation date of each unit and amortized over the life of the units.

(h) Deferral of net loss (gain) associated with the change in fair value of the interest rate options to hedge interest rates on a portion of expected borrowings related to Plant Vogtle Units No.3 and No.4 construction. Amortization will commence effective with the expected principal repayment of the DOE-guaranteed loan and amortized over the expected remaining life of DOE-guaranteed loan which will finance the construction project.

(i) Effects on net margin for Smith and Hawk Road Energy Facilities will be deferred until the end of 2015 and amortized over the remaining life of each plant.

(j) The amortization period for other regulatory assets range up to 36 years and the amortization period of other regulatory liabilities range up to 8 years.

(k) Net benefit associated with Rocky Mountain lease transactions is amortized to income over the 30-year lease-back period. For a discussion of Rocky Mountain leases, see Note 4.

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

(m) Collections to fund debt payments in excess of depreciation expense through the end of 2025; deferred revenues will be amortized over the remaining useful life of the plants.

t. Other income

The components of other income within the Consolidated Statement of Revenues and Expenses were as follows:

	(dollars in thousands) 2012	2011	2010
Capital credits from associated companies (Note 4)	**$ 1,919**	$ 2,095	$ 2,096
Net revenue from Georgia Transmission and Georgia System Operations for shared Administrative and General costs	**4,280**	4,071	3,834
Miscellaneous other	**214**	38	(564)
Total	**$ 6,413**	$ 6,204	$ 5,366

u. Presentation

Certain prior year amounts have been reclassified to conform with the current year presentation.

v. New accounting pronouncements

In May 2011, the Financial Accounting Standards Board issued "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards." The amendments change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, but generally do not result in a change in the application of ASC 820 "Fair Value Measurements." These changes were effective for us on January 1, 2012. Our adoption of this standard did not have a material effect on our consolidated financial statements.

In June 2011, the FASB issued "Comprehensive Income (Topic 220) Presentation of Financial Statements" which amended certain provisions of ASC 220 "Comprehensive Income." These provisions change the presentation requirements for other comprehensive income and total comprehensive income and require one continuous statement or two separate but consecutive statements. Presentation of other comprehensive income in the statement of stockholders' equity is no longer permitted. These provisions are effective for fiscal and interim periods beginning after December 15, 2011. The adoption of these provisions did not have a material effect on our consolidated financial statements.

In December 2011, the FASB issued "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities," which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. This guidance is effective for our fiscal year ending December 31, 2013. We do not expect the adoption of this standard to have a material impact on our consolidated financial statements.

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.

The table below details assets and liabilities measured at fair value on a recurring basis for the periods ending December 31, 2012 and 2011, respectively.

		Fair Value Measurements at Reporting Date Using			
	December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
		(dollars in thousands)			
Nuclear decommissioning trust funds:					
Domestic equity	**$ 118,329**	$ 118,329	$ –	$ –	(1)
International equity	**48,105**	48,105	–	–	(1)
Corporate bonds	**53,172**	–	53,172	–	(1)
U.S. Treasury and government agency securities	**46,626**	46,626	–	–	(1)
Agency mortgage and asset backed securities	**21,273**	–	21,273	–	(1)
Other	**13,280**	13,280	–	–	(1)
Long-term investments:					
Corporate bonds	**5,762**	–	5,762	–	(1)
U.S. Treasury and government agency securities	**7,387**	7,387	–	–	(1)
Agency mortgage and asset backed securities	**2,526**	–	2,526	–	(1)
Mutual funds	**60,972**	60,972	–	–	(1)
Other	**375**	375	–	–	(1)
Interest rate options	**25,783**(1)	–	–	25,783	(3)
Natural gas swaps	**(1,085)**	–	(1,085)	–	(1)

		Fair Value Measurements at Reporting Date Using			
	December 31, 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
		(dollars in thousands)			
Nuclear Decommissioning trust funds:					
Domestic equity	$ 102,285	$ 102,285	$ –	$ –	(1)
International equity	39,618	39,618	–	–	(1)
Corporate bonds	41,338	–	41,338	–	(1)
U.S. Treasury and government agency securities	41,697	41,697	–	–	(1)
Agency mortgage and asset backed securities	28,519	–	28,519	–	(1)
Derivative instruments	(982)	–	–	(982)	(3)
Other	16,122	16,122	–	–	(1)
Long-term investments:					(1)
Mutual funds	75,062	75,062	–	–	(1)
Auction rate securities	7,713	–	–	7,713(2)	(3)
Interest rate options	69,446(1)	–	–	69,446	(3)
Natural gas swaps	(7,220)	–	(7,220)	–	(1)

(1) Interest rate options as reflected on the Consolidated Balance Sheet includes the fair value of the interest rate options offset by $8,950,000 and $43,070,000 of collateral received by the counterparties at December 31, 2012 and 2011, respectively.

(2) Represents auction rate securities investments we held.

The Level 2 investments above in corporate bonds and agency mortgage and asset backed securities may not be exchanged 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 following tables present the changes in Level 3 assets measured at fair value on a recurring basis during the years ended December 31, 2012 and 2011, respectively.

	Year Ended December 31, 2012		
	Nuclear decommissioning trust funds	Long-term investments	Interest rate options
	(dollars in thousands)		
Assets:			
Balance at December 31, 2011	$ (982)	$ 7,713	$ 69,446
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets)	982	887	(43,663)
Purchases, issuances, liquidations	–	(8,600)	–
Balance at December 31, 2012	**$ –**	**$ –**	**$ 25,783**

	Year Ended December 31, 2011		
	Nuclear decommissioning trust funds	Long-term investments	Interest rate options
	(dollars in thousands)		
Assets:			
Balance at December 31, 2010	$ (452)	$ 8,671	$ –
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets)	(530)	142	(30,554)
Purchases, issuances, liquidations	–	(1,100)	100,000
Balance at December 31, 2011	$ (982)	$ 7,713	$ 69,446

The assets included in the "Long-term investments" column in each of the Level 3 tables above are auction rate securities. On February 15, 2012, we sold our remaining $8,600,000 of auction rate securities, which resulted in a loss of $1,075,000. The loss was recorded as a regulatory asset and is being charged to income over a period of four years. As a result of market conditions, including the failure of auctions for the auction rate securities in which we had invested, the fair value of these auction rate securities in prior periods were determined using an income approach based on a discounted cash flow model. The discounted cash flow model utilized projected cash flows at current rates, which was adjusted for illiquidity premiums based on discussions with market participants.

The estimated fair values of our long-term debt, including current maturities at December 31, 2012 and 2011 were as follows (in thousands):

	2012		2011	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 5,930,449**	**$ 7,213,365**	$ 5,692,504	$ 6,908,763

The fair value of long-term debt is primarily level 2 and is estimated based on quoted market prices for the same or similar issues or on the current rates offered to us for debt of similar maturities. Our three primary sources of long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC) and by CoBank, ACB in addition to a multi-year term loan with Bank of Tokyo. The valuations for the first mortgage bonds and the pollution control revenue bonds are provided by a third-party investment banking firms. These valuations are based on market prices for similar debt in active markets. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of December 31, 2012 (plus a spread of ⅛ percent). The additional spread of ⅛ percent is reflective of the "cost" the Rural Utilities Service attributes to making these loans. We use an interest rate quote sheet provided by CoBank for valuation of the CoBank debt. The quotes contained in CoBank's rate sheet are adjusted for our "A" credit rating. The rates on the CFC debt are fixed and the valuation is based on rate quotes provided by CFC. The rate in effect at December 31, 2012 for our term loan, which resets each month and is based on a 1.25% spread to LIBOR was used for valuation of the term loan.

We use the methods and assumptions described above to estimate the fair value of each class of financial instruments. For cash and cash equivalents, restricted cash and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments.

3. Derivative instruments:

Our risk management and compliance committee provides general oversight over all risk management and compliance activities, including but not limited to, commodity trading, investment portfolio management and interest rate risk management. We use commodity trading derivatives to manage our exposure to fluctuations in the market price of natural gas. Prior to December 2012, our commodity trading derivatives were generally designated as hedging instruments under authoritative guidance for accounting for derivatives and hedging. In December 2012, we discontinued hedge accounting for these derivatives and currently apply regulatory accounting. Consistent with our rate-making, unrealized gains or losses on natural gas swaps are reflected as a regulatory asset or liability. To hedge 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, we have entered into interest rate options. Hedge accounting is not applied to our interest rate options. Consistent with our rate-making, unrealized gains or losses from the interest rate options are recorded as a regulatory asset. Within our nuclear decommissioning trust fund, derivatives including options, swaps and credit default swaps which are non-speculative, could be utilized to mitigate volatility associated with duration, default, yield curve and the interest rate risks of the portfolio. Consistent with our rate-making, unrealized gains or losses related to decommissioning trust fund are recorded as an increase or decrease in the associated regulatory asset or liability. We do not hold or enter into derivative transactions for trading or speculative purposes.

We are exposed to credit risk as a result of entering into these hedging 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 and/or interest rates could cause us to have credit risk exposures with one or more natural gas counterparties, and we currently have credit risk exposure to our interest rate options counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of December 31, 2012, all of the counterparties with transaction amounts outstanding under our hedging 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 hedge and interest rate option 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.

Gas hedges. 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, 2012 and 2011 the estimated fair value of our natural gas contracts was a liability of approximately $1,085,000 and $7,220,000, respectively.

As of December 31, 2012 and 2011, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit totaling up to $909,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of December 31, 2012 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2013	4.4
2014	1.0
Total	**5.4**

Interest rate options. 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. In fourth quarter of 2011, we purchased interest rate options at a cost of $100,000,000 to hedge the interest rates on approximately $2.2 billion of the expected debt that will be used to finance the new Vogtle units.

The interest rate options, commonly known as LIBOR swaptions, give us the right, but not the obligation, to enter into a swap in which we would pay a fixed rate and receive a floating LIBOR rate. However, the swaptions are required to be cash settled based on their value on the expiration date, thereby effectively capping our interest rates by offsetting the present value cost of an increase in interest rates above the fixed rate. The cash settlement value depends on the extent to which prevailing LIBOR swap rates exceed the fixed rate on the underlying swap, and the value would be zero if swap rates are at or below the fixed rate upon expiration. The fixed rates on the LIBOR swaptions we purchased were in the range of 150 to 200 basis points above LIBOR swap rates in effect as of December 31, 2012 and the weighted average fixed rate is 4.17%. The swaptions' expiration dates, which range from 2013 through 2017, are timed to match the borrowing schedule for the new Vogtle units that was in place when we implemented this hedging program.

We paid the entire premiums at the time we entered into these interest rate option transactions and have no additional payment obligations. However, upon expiration of the interest rate options, each counterparty will be obligated to pay us the cash value of the interest rate options, if any. These derivatives are recorded at fair value and hedge accounting is not applied. At December 31, 2012 and 2011, the fair value of these interest rate options was approximately $25,783,000 and $69,446,000, respectively. To manage our credit exposure to these counterparties, we negotiated credit support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the interest rate options outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from $0 to $10,000,000 depending on each counterparty's credit rating. As of December 31, 2012 and 2011, we held $8,950,000 and $43,070,000 of funds posted as collateral by the counterparties, respectively. The collateral received is recorded as restricted cash on our consolidated balance sheet. The liability associated with the collateral is recorded as an offset to the fair values of the interest rate options, which are recorded within other deferred charges on the consolidated balance sheet, resulting in a net carrying amount of the interest rate options of $16,833,000 and $26,376,000 at December 31, 2012 and 2011, respectively.

We are deferring gains or losses from the change in fair value of each interest rate option and related carrying and other incidental costs in accordance with our rate-making treatment. The deferred costs and deferred gains, if any, from the settlement of the interest rate options will be amortized and collected in rates over the life of the $2.2 billion of debt that we hedged with the swaptions.

We estimate the value of the LIBOR swaptions utilizing an option pricing model based on several inputs including the notional amount, the forward LIBOR swap rates, the option volatility, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, as well as credit attributes, including the credit spread of the counterparty and the amount of credit support that is available for each swaption. The fair value of the swaptions is sensitive to certain of these inputs, especially option volatility. We are able to effectively observe all of these factors using a variety of market sources except for the credit spreads of certain counterparties and the option volatility. We are able to estimate option volatility implied by valuations we obtain from various sources, but the valuations, and therefore the implied option volatilities vary considerably from one source to another. Since valuations of comparable instruments are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We considered both any intrinsic value and the remaining time value associated with the derivatives and considered counterparty credit risk in our determination of all estimated fair values. We believe the estimated fair values for the LIBOR swaptions we hold are based on the most accurate information available for these types of derivative contracts.

The following table reflects the notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of December 31, 2012.

Year	LIBOR Swaption Notional Dollar Amount (in thousands)
2013	$ 754,452
2014	563,425
2015	470,625
2016	310,533
2017	80,169
Total	**$ 2,179,204**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at December 31, 2012 and December 31, 2011.

	Balance Sheet Location	Fair Value	
		2012	2011
		(dollars in thousands)	
Designated as hedge:			
Liabilities			
Natural gas swaps	Other current liabilities	**$ –**	$ 7,220
Not designated as hedge:			
Assets			
Nuclear decommissioning trust	Nuclear Decommissioning trust fund	**$ –**	$ (982)
Interest rate options	Other deferred charges	**$ 25,783**	$ 69,446
Liabilities			
Natural gas swaps	Other current liabilities	**$ 1,085**	$ –

The following table presents the realized gains and (losses) on derivative instruments recognized in margin for the year ended December 31, 2012 and December 31, 2011.

	Consolidated Statement of Revenues and Expenses Location	2012	2011	2010
		(dollars in thousands)		
Designated as hedge:				
Natural Gas Swaps	Fuel	**$ –**	$ 195	$ –
Natural Gas Swaps	Fuel	**–**	(4,151)	(19,734)
		$ –	$ (3,956)	$ (19,734)
Not designated as hedge:				
Natural Gas Swaps	Fuel	**$ 2,338**	$ –	$ –
Natural Gas Swaps	Fuel	**(10,483)**	–	–
		$ (8,145)	$ –	$ –

The following table presents the unrealized gains and (losses) on derivative instruments deferred on the balance sheet at December 31, 2012 and 2011.

	Consolidated Balance Sheet Location	2012	2011	2010
Designated as hedge:				
Natural Gas Swaps	Accounts receivable	**$ –**	$ (7,220)	$ (2,054)
Total designated as hedge				
Not designated as hedge:				
Natural Gas Swaps	Regulatory asset	**$ (1,085)**	$ –	$ –
Nuclear Decommissioning Trust	Regulatory asset	**–**	3,602	2,689
Nuclear Decommissioning Trust	Regulatory asset	**–**	(2,557)	(2,564)
Interest Rate Options	Regulatory asset	**(74,217)**	(30,554)	–
Total not designated as hedge		**$ (75,302)**	$ (29,509)	$ 125

4. Investments:

Investments in debt and equity securities

Investment securities we hold are classified as available-for-sale. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from patronage capital, except that, in accordance with our rate-making treatment, unrealized gains and losses from investment securities held in the nuclear decommissioning trust fund are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 95% of these gross unrealized losses were in effect for less than one year.

For those securities considered to be available-for-sale, the following table summarizes the activities for those securities as of December 31, 2012 and 2011:

(dollars in thousands)

2012	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
Equity	**$ 153,846**	**$ 45,071**	**$ (3,675)**	**$ 195,242**
Debt	**163,127**	**10,286**	**(4,501)**	**168,912**
Other	**13,654**	**–**	**–**	**13,654**
Total	**$ 330,627**	**$ 55,357**	**$ (8,176)**	**$ 377,808**

(dollars in thousands)

2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Equity	$ 149,263	$ 29,789	$ (9,996)	$ 169,056
Debt	160,218	18,021	(11,063)	167,176
Other	15,646	1,035	(1,541)	15,140
Total	$ 325,127	$ 48,845	$ (22,600)	$ 351,372

All of the available-for-sale investments are marked to market in the accompanying consolidated balance sheets, therefore the carrying value equals the fair value.

The contractual maturities of debt securities available-for-sale, which are included in the estimated fair value table above, at December 31, 2012 and 2011 are as follows:

(dollars in thousands)

	2012 Cost	**2012 Fair Value**	2011 Cost	2011 Fair Value
Due within one year	**$ 2,265**	**$ 2,191**	$ 2,074	$ 2,051
Due after one year through five years	**43,050**	**43,533**	32,149	32,598
Due after five years through ten years	**68,893**	**71,217**	68,987	74,010
Due after ten years	**48,919**	**51,971**	57,008	58,517
Total	**$ 163,127**	**$ 168,912**	$ 160,218	$ 167,176

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2012, 2011 and 2010:

(dollars in thousands)

For the years ended December 31,	**2012**	2011	2010
Gross realized gains	**$ 28,959**	$ 31,130	$ 24,634
Gross realized losses	**(18,175)**	(16,215)	(10,395)
Proceeds from sales	**666,481**	1,064,377	622,124

Investment in associated companies

Investments in associated companies were as follows at December 31, 2012 and 2011:

	(dollars in thousands) 2012	2011
National Rural Utilities Cooperative Finance Corporation (CFC)	**$ 24,005**	$ 23,993
CoBank, ACB	**2,931**	3,345
CT Parts, LLC	**7,128**	5,633
Georgia Transmission Corporation	**20,867**	19,291
Georgia System Operations Corporation	**4,375**	3,911
Other	**1,464**	1,453
Total	**$ 60,770**	$ 57,626

The CFC investments are primarily in the form of capital term certificates and are required in conjunction with our membership in CFC. Accordingly, there is no market for these investments. The investments in CoBank and Georgia Transmission represent capital credits. Any distributions of capital credits are subject to the discretion of the board of directors of CoBank and Georgia Transmission. The investments in Georgia System Operations represent loan advances. The loan repayment schedule ends in December 2015.

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

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 own facilities. For 2012, 2011, and 2010, we incurred expenses from Georgia Transmission of $26,035,000, $25,128,000, and $25,491,000, respectively.

We, Georgia Transmission and 37 of our members are members of Georgia Systems Operations. Georgia Systems Operations operates the system control center and currently provides us system operations services and administrative support services. For 2012, 2011, and 2010, we incurred expenses from Georgia Systems Operations of $18,870,000, $17,793,000, and $16,848,000, respectively.

Smarr EMC is a Georgia electric membership corporation owned by 35 of our 38 members. Smarr EMC owns two combustion turbine facilities. We provide operations, financial and management services for Smarr EMC.

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 five leases were each owned by separate owner trusts for the benefit of two of the owner participants, and represented approximately 90% of the six original lease transactions. As a result, only one of the original lease arrangements, approximately 10% of the original lease transactions, remains in place. In connection with these terminations, we incurred termination costs of $22,500,000 and recognized $41,400,000 of the deferred net benefit associated with the terminated leases, resulting in a net gain on termination of $18,900,000. The termination of these five leases significantly reduced our exposure to the credit counterparties participating in the leases.

The assets of RMLC are not available to pay our creditors or our affiliates', other than RMLC, creditors.

5. Income taxes:

We are a not-for-profit membership corporation subject to federal and state income taxes. As a taxable electric cooperative, we have annually allocated income and deductions between patronage and non-patronage activities.

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 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:

	2012	2011	2010
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Patronage exclusion	**(32.7%)**	(32.6%)	(32.9%)
Tax credits	**0.0%**	0.0%	0.0%
Other	**(2.3%)**	(2.4%)	(2.1%)
Effective income tax rate	**0.0%**	0.0%	0.0%

The components of the net deferred tax assets and liabilities as of December 31, 2012 and 2011 were as follows:

	(dollars in thousands) 2012	2011
Deferred tax assets		
Net operating losses	**$ 29,724**	$ 29,724
Tax credits (alternative minimum tax and other)	**1,535**	1,535
Accounting for Rocky Mountain transactions	**347,867**	334,423
Other assets	**18,859**	14,312
Deferred tax assets	**397,985**	379,994
Less: Valuation allowance	**(31,259)**	(31,259)
Net deferred tax assets	**$ 366,726**	$ 348,735
Deferred tax liabilities		
Depreciation	**$ 465,598**	$ 485,721
Accounting for Rocky Mountain transactions	**157,145**	161,214
Other liabilities	**44,508**	39,109
Deferred tax liabilities	**667,251**	686,044
Net deferred tax liabilities	**300,525**	337,309
Less: Patronage exclusion	**(300,525)**	(337,309)
Net deferred taxes	**$ –**	$ –

As of December 31, 2012, we have federal and state tax net operating loss carryforwards and alternative minimum tax credits as follows:

Expiration Date	(dollars in thousands) Minimum Alternative Tax Credits	NOLs
2018	$ –	$ 61,533
2019	–	10,516
2020	–	4,362
None	1,535	–
	$ 1,535	$ 76,411

The net operating loss expiration dates start in the year 2018 and end in the year 2020. Due to the tax basis method for allocating patronage and as shown by the above valuation allowance, it is not likely that the deferred tax assets related to tax credits and net operating losses will be realized.

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 2009 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 2009 forward.

6. Capital leases:

In 1985, we sold and subsequently leased back from four purchasers their 60% undivided ownership interest in Scherer Unit No. 2. The gain from the sale is being amortized over the terms of the leases. In June 2012, under the provisions of the leases, we executed irrevocable notices of renewal to the leases beyond their base terms, for a period of 14.5 years, through December 31, 2027, for three of the leases and for a period of 18 years, through June 30, 2031, for one of the leases.

In 2000, we entered into a power purchase and sale agreement with Doyle I, LLC (Doyle Agreement) to purchase all of the output from a five-unit generation facility (Doyle) for a period of 15 years.

The minimum lease payments under the capital leases together with the present value of the net minimum lease payments as of December 31, 2012 are as follows:

Year Ending December 31,	(dollars in thousands)		
	Scherer Unit No. 2	Doyle	Total
2013	$ 23,406	$ 12,447	$ 35,853
2014	14,949	12,447	27,396
2015	14,949	18,297	33,246
2016	14,949	–	14,949
2017	14,949	–	14,949
2018-2031	160,178	–	160,178
Total minimum lease payments	243,380	43,191	286,571
Less: Amount representing interest	(121,258)	(4,064)	(125,322)
Present value of net minimum lease payments	122,122	39,127	161,249
Less: Current portion	(14,924)	(10,382)	(25,306)
Long-term balance	$ 107,198	$ 28,745	$ 135,943

For Doyle, the lease payments vary to the extent the interest rate on the lessor's debt varies from 6.00%. At December 31, 2012, the weighted average interest rate on the Doyle lease obligation was 5.90% as compared to 5.86% at December 31, 2011.

The Scherer No. 2 lease and the Doyle Agreement are reported as capital leases. For rate-making purposes, however, we include the actual lease payments in our cost of service. The difference between lease payments and the aggregate of the amortization on the capital lease asset and the interest on the capital lease obligation is recognized as a regulatory asset on the balance sheet. Capital lease amortization is recorded in depreciation and amortization expense.

7. Debt:

Long-term debt consists of first mortgage notes payable to the United States of America acting through the Federal Financing Bank and the Rural Utilities Service, first mortgage bonds payable, first mortgage notes issued in conjunction with the sale by public authorities of pollution control revenue bonds, first mortgage notes payable to CoBank and CFC and unsecured notes payable to three commercial banks. 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, the first mortgage notes issued in conjunction with the sale of pollution control revenue bonds, and the CoBank and CFC first mortgage notes.

On November 30, 2012, we issued $250,000,000 of 4.20% First Mortgage Bonds, Series 2012 A primarily for the purpose of providing long-term financing for costs related to the construction of Vogtle Units No. 3 and No. 4 and for long-term financing for the portion of the acquisition cost of the Smith Facility that the Rural Utilities Service is not financing. The first mortgage bonds are secured under our first mortgage indenture.

In March 2013, instead of remarketing $212,760,000 of pollution control revenue bonds, that were originally issued on our behalf by the Development Authorities of Appling, Burke and Monroe Counties, and were subject to mandatory tender on March 1, 2013, we elected to refund the bonds with commercial paper.

During 2012, we received advances on Rural Utilities Service guaranteed Federal Financing Bank loans totaling $107,390,000 for environmental and general improvements at existing plants.

Maturities for long-term debt and capital lease obligations through 2017 are as follows:

	2013	2014	2015	2016	2017
	(dollars in thousands)				
FFB	$ 103,407	$ 107,663	$ 112,206	$ 116,558	$ 113,644
CFC	767	806	848	891	937
CoBank	551	621	698	786	885
PCBs(1)	37,352	37,352	170,902	–	–
CREBs	1,010	1,010	1,010	1,010	1,010
Term Loans	–	260,000	–	–	–
	143,087	407,452	285,664	119,245	116,476
Capital Leases	25,306	14,212	21,275	3,955	4,404
Total	$ 168,393	$ 421,664	$ 306,939	$ 123,200	$ 120,880

(1) These are not regularly scheduled principal payments but instead represent i) amounts that would be due if the credit support facilities for the Series 2009 and 2010 pollution control bonds were drawn upon and became payable in accordance with their terms. To date, none of the credit support facilities backing the Series 2009 and 2010 bonds have been drawn upon for principal and we anticipate extending these facilities before their expiration. The nominal maturities of the 2009 and 2010 pollution control bonds range from 2030 through 2038.

The weighted average interest rate for long-term debt and capital leases was 4.73% at December 31, 2012 as compared to 4.85% at December 31, 2011.

We have $1,925,000,000 of committed credit arrangements comprised of five separate facilities with maturity dates that range from December 2013 to September 2016. These short-term 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, we have the ability to issue letters of credit totaling $835,000,000 in the aggregate, of which $583,000,000 remained available at December 31, 2012. At December 31, 2012, we had 1) $253,000,000 under these lines of credit in the form of issued letters of credit supporting variable rate demand bonds and to post collateral to third parties, and 2) $569,000,000 dedicated under one of these lines of credit to support a like amount of commercial paper we issued that is outstanding.

The weighted average interest rate on short-term borrowings was 0.44% at December 31, 2012 as compared to 0.26% at December 31, 2011.

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 its' 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, 2012 and 2011 is as follows:

	2012		2011	
	(dollars in thousands)			
Plant	Investment	Accumulated Depreciation	Investment	Accumulated Depreciation
In-service[1]				
Owned property				
Vogtle Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**$ 2,745,800**	**$ (1,566,133)**	$ 2,726,129	$ (1,528,841)
Vogtle Unit No. 3 & No. 4 *(Nuclear – 30% ownership)*	**8,956**	**(147)**	–	–
Hatch Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**645,722**	**(361,554)**	603,865	(369,189)
Wansley Units No. 1 & No. 2 *(Fossil – 30% ownership)*	**441,340**	**(147,890)**	394,596	(129,994)
Scherer Unit No. 1 *(Fossil – 60% ownership)*	**696,223**	**(288,701)**	663,583	(269,525)
Rocky Mountain Units No. 1, No. 2 & No. 3 *(Hydro – 75% ownership)*	**585,133**	**(187,763)**	584,569	(176,356)
Hartwell *(Combustion Turbine – 100% ownership)*	**224,374**	**(89,822)**	223,936	(85,337)
Hawk Road *(Combustion Turbine – 100% ownership)*	**243,963**	**(56,593)**	241,587	(51,253)
Talbot *(Combustion Turbine – 100% ownership)*	**281,009**	**(86,000)**	280,413	(77,616)
Chattahoochee *(Combined cycle – 100% ownership)*	**301,246**	**(88,272)**	299,117	(79,285)
Smith *(Combined cycle – 100% ownership)*	**553,942**	**(123,575)**	554,158	(109,741)
Wansley *(Combustion Turbine – 30% ownership)*	**3,624**	**(3,161)**	3,684	(3,084)
Transmission plant	**84,801**	**(45,381)**	78,470	(41,539)
Other	**109,461**	**(67,415)**	106,083	(64,433)
Property under capital lease:				
Doyle *(Combustion Turbine – 100% leasehold)*	**126,990**	**(82,546)**	126,990	(80,030)
Scherer Unit No. 2 *(Fossil – 60% leasehold)*	**454,123**	**(277,134)**	448,686	(262,362)
Total in-service	**$ 7,506,707**	**$ (3,472,087)**	$ 7,335,866	$ (3,328,585)
Construction work in progress				
Vogtle Unit No. 3 & No. 4	**$ 1,613,791**		$ 1,287,649	
Environmental and other generation improvements	**626,264**		495,597	
Other	**865**		1,018	
Total construction work in progress	**$ 2,240,920**		$ 1,784,264	

(1) Amounts include plant acquisition adjustments at December 31, 2012 and 2011 of $196,000,000 and $198,000,000, respectively.

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 or depreciation) on the accompanying statements of revenues and expenses.

b. Construction

In April 2008, Georgia Power, acting for itself and as agent for Oglethorpe, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia (collectively, the Co-owners), and Westinghouse Electric Company LLC (Westinghouse) and Stone &

Webster, Inc. (collectively, the Contractor) entered into an engineering, procurement, and construction agreement (Vogtle No. 3 and No. 4 Agreement) to design, engineer, procure, construct, and construct two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle Units No. 3 and No. 4).

The Vogtle No. 3 and No. 4 Agreement is an arrangement whereby the Contractor supplies and constructs the entire facility with the exception of certain items provided by the Co-owners. Under the terms of the Vogtle No. 3 and No. 4 Agreement, the Co-owners will pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders, and performance bonuses. Each Co-owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle No. 3 and No. 4 Agreement. Our proportionate share is 30.0%.

The Co-owners and the Contractor have agreed to certain liquidated damages upon the Contractor's failure to comply with the schedule and performance guarantees. The Contractor's liability to the Co-owners for schedule and performance liquidated damages and for warranty claims is subject to a cap.

The NRC certified the Westinghouse AP1000 Design Control Document (DCD) effective December 30, 2011. On February 10, 2012, the NRC issued combined construction permits and operating licenses (COLs) for Vogtle Units No. 3 and No. 4 which allowed full construction to begin.

There are pending technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4, including legal challenges to the NRC's issuance of the COLs and certification of the DCD. Similar additional challenges at the federal and state level are expected as construction proceeds.

During the development and construction process, issues have materialized that have caused revisions to the estimated project schedule and cost. Georgia Power has revised the estimated commercial operation dates for Units No. 3 and No. 4 from April of 2016 and 2017, respectively, to the fourth quarter of 2017 and 2018, respectively. Additionally, our estimated cost for the new units, including allowance for funds used during construction, is approximately $4,500,000,000, an increase from our original $4,200,000,000 estimate. Commercial responsibility for the revised commercial operation dates and additional costs remain in dispute.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards or other issues, including the litigation discussed in Note 13a, may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the contract, but also may be resolved through litigation.

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

At December 31, 2012, our total capitalized costs were approximately $1,689,000,000.

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. Our current policy is to match the employee's contribution as long as there is sufficient margin to do so. 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 $1,016,000 in 2012, $925,000 in 2011 and $867,000 in 2010. Our contribution to the employer retirement contribution feature was 8%. Our contributions to the employer retirement contribution feature of the 401(k) plan were approximately $2,029,000 in 2012, $1,844,000 in 2011 and $1,712,000 in 2010.

10. Nuclear insurance:

The Price-Anderson Act, limits public liability claims that could arise from a single nuclear incident to $12,600,000,000. 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'') (in the amount of $375,000,000 for each plant, the maximum amount currently available) 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 $375,000,000, a licensee of a nuclear power plant could be assessed a deferred premium of up to $117,500,000 per incident for each licensed reactor operated by it, but not more than $17,500,000 per reactor per incident to be paid in a calendar year. On the basis of our ownership interest in four nuclear reactors, we could be assessed a maximum of $141,000,000 per incident, but not more than $21,000,000 in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years, and exclude any applicable state premium taxes. The next scheduled adjustment is due no later than October 29, 2013.

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 $500,000,000 for members' operating nuclear generating facilities. Additionally, Georgia Power provides coverage through NEIL for decontamination, premature decommissioning and excess property damage to nuclear generating facilities for an additional $2,250,000,000 for losses in excess of the $500,000,000 primary coverage described above.

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 $2,750,000,000 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 under that policy. 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 $32,200,000.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3,200,000,000 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 the company or to its 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:

a. Operating leases

As of December 31, 2012, our estimated minimum rental commitments for our railcar leases for use at our coal-fired facilities over the next five years and thereafter are as follows:

	(dollars in thousands)
2013	$ 5,743
2014	5,743
2015	4,412
2016	4,412
2017	4,412
Thereafter	7,041

The rental expenses for the railcar leases are added to the cost of the fossil inventories and are recognized in fuel expense. Rental expenses totaled $5,164,000 in 2012, $5,190,000 in 2011 and $5,265,000 in 2010.

b. Fuel

To supply a portion of the fuel requirements to our generating units, Southern Nuclear on our behalf for nuclear fuel, and Georgia Power, on our behalf for coal, 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 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 or government impositions. For further discussion of total nuclear fuel expense, see Note 1h. As of December 31, 2012, our estimated minimum long-term commitments are as follows:

(dollars in thousands)	Coal	Nuclear Fuel
2013	$ 78,000	$ 72,000
2014	41,000	57,000
2015	–	36,900
2016	–	29,100
2017	–	26,100
Thereafter	–	138,000

12. Guarantees:

As of December 31, 2012 and 2011, we had guarantees for rental payments due under the terms of the Rocky Mountain lease transactions and replacement credit enhancement. We estimate that the current maximum aggregate amount of exposure we would have if we were required to purchase the equity interests of the remaining owner trust under the Rocky Mountain lease transactions is approximately $25,000,000. See Note 4 for discussion of Rocky Mountain lease transactions.

13. Contingencies and Regulatory Matters:

a. Nuclear Construction

Under the Vogtle No. 3 and No. 4 Agreement, the Co-Owners and the Contractor for have established both informal and formal dispute resolution procedures in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, has successfully initiated both formal and informal claims through these procedures, including ongoing claims. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and the Co-owners are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

The most significant litigation relates to costs associated with design changes to the DCD and costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs by the NRC. In July 2012, the Co-owners and Contractor began negotiations regarding these costs, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the contract. The Contractor has claimed that its estimated adjustment attributable to us, based on our ownership interest, is approximately $280,000,000 in 2008 dollars with respect to these issues. The Contractor has also asserted that it is entitled to schedule extensions. Georgia Power, on behalf of the Co-owners, has not agreed with either the proposed cost or schedule adjustments or that the Co-owners have any responsibility for costs related to these issues. On November 1, 2012, the Co-owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia, seeking a declaratory judgment that the Co-owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Co-owners in the U.S. District Court for the District of Columbia alleging the Co-owners are responsible for these costs. Georgia Power and the Co-owners intend to vigorously defend their positions. During litigation, Georgia Power and the Co-owners expect negotiations with the Contractor to continue with respect to cost and schedule during which time the parties will attempt to reach a mutually acceptable compromise of their positions. If any or all of these costs are ultimately imposed on the Co-owners, we will capitalize the costs attributable to us. As of December 31, 2012, no material amounts have been recorded related to this claim. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction.

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

b. Environmental and Other 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 are also subject to climate change regulations that impose restrictions on emissions of greenhouse gases, including carbon dioxide, for certain new and modified facilities.

In general, these and other types of environmental requirements are becoming increasingly stringent. Such requirements may substantially increase the cost of electric service, by requiring modifications in the design or operation of existing facilities, the purchase of emission allowances, or changes or delays in the location, design, construction or operation of new facilities. 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 or 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 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. For example, in January 2013, several plaintiffs filed complaints against us and the other co-owners of Plant Scherer claiming personal injury and property damage arising from the alleged release of hazardous substances from the plant, primarily related to the coal-ash pond, into the surrounding groundwater and air.

Except as discussed in Note 13a, management does 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.

14. Plant acquisition:

Thomas A. Smith Energy Facility

On April 8, 2011, we acquired 100% of KGen Murray I and II LLC, a wholly owned subsidiary of KGen Power Corporation. KGen Murray I and II LLC, subsequently renamed Murray I and II, LLC, owns the Smith Energy Facility, located near Dalton, Georgia. This facility consists of two natural gas-fired combined cycle units that have an aggregate summer planning reserve generation capacity of approximately 1,250 megawatts.

As part of the acquisition, we assumed an existing power purchase and sale agreement with Georgia Power for the entire output of Smith Unit No. 1 that expired May 31, 2012. Our members generally plan to take the output of Smith beginning in 2016 in connection with their forecasted power requirements. Prior to our members' use of Smith, energy is being sold into the wholesale market in order to reduce the net cost of this facility to our members.

We accounted for the transaction as a purchase business combination. In connection with the acquisition, which included acquisition related costs of approximately $1,962,000 (consisting primarily of legal and professional services which are recorded in the accompanying statement of revenues and expenses for the year ended December 31, 2011), we funded the entire $532,255,000 cash outlay by closing a $260,000,000 three-year term loan and by financing the remaining $272,255,000 through the issuance of commercial paper.

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

	(in millions)
Recognized fair value amounts of identifiable assets acquired and liabilities assumed:	
Property, plant and equipment	$ 456.7
Inventory	34.0
Other current assets	4.6
Power purchase and sale agreement	40.4
Emission credits	0.2
Current liabilities	(5.6)
Total identifiable net assets	**$ 530.3**

There was no goodwill associated with this acquisition.

We have consolidated the financial position and results of operations of Smith as of April 8, 2011. Our revenues for the year ended December 31, 2012 and 2011 include $119,723,000 and $165,389,000 of non-member sales from Smith. Prior to our members taking the output from Smith, the net results of operations from Smith, including related interest costs, are being deferred as a regulatory asset as such amounts represent an additional cost incurred to acquire Smith. The regulatory asset will be amortized over the remaining life of the plant (estimated to be 30 years) beginning in 2016. For the years ended December 31, 2011 and 2012, we deferred net costs of $3,536,000 and $17,582,000, respectively.

15. Quarterly financial data (unaudited)

Summarized quarterly financial information for 2012 and 2011 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(dollars in thousands)			
2012				
Operating revenues	**$ 319,224**	**$ 347,703**	**$ 377,396**	**$ 279,787**
Operating margin	**62,056**	**63,919**	**61,051**	**34,807**
Net margin	**13,520**	**10,878**	**23,743**	**(8,821)**
2011				
Operating revenues	$ 269,774	$ 379,803	$ 432,530	$ 308,171
Operating margin	65,935	63,702	64,884	43,299
Net margin	16,110	12,718	10,408	(1,499)

Our business is influenced by seasonal weather conditions. The negative net margins in the fourth quarter of 2012 and 2011 were due to reductions to revenue requirements in order to achieve the targeted margins for interest ratio of 1.14.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Members of Oglethorpe Power Corporation

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Oglethorpe Power Corporation as of December 31, 2012 and 2011, and the related consolidated statements of revenues and expenses, comprehensive margin, patronage capital and membership fees and accumulated other comprehensive margin (deficit), and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included the consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Oglethorpe Power Corporation at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Atlanta, Georgia
March 22, 2013

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, 2012 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 issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation under the framework in Internal Control – Integrated Framework issued by Committee of Sponsoring Organizations, our management concluded that our internal control over financial reporting was effective as of December 31, 2012 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 identified in connection with the above-referenced evaluation by management of the effectiveness of our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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 independent outside directors. Our bylaws divide member director positions among the member scheduling groups specifically described in the bylaws, referred to as the ''member groups.'' 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 must each 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.

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 that. 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 nor any of our 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 insure 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:		
Thomas A. Smith	58	President and Chief Executive Officer
Michael W. Price	52	Executive Vice President and Chief Operating Officer
Elizabeth B. Higgins	44	Executive Vice President and Chief Financial Officer
William F. Ussery	48	Executive Vice President, Member and External Relations
W. Clayton Robbins	66	Senior Vice President, Governmental Affairs
Charles W. Whitney	66	Senior Vice President and General Counsel
Jami G. Reusch	50	Vice President, Human Resources
Directors:[(1)]		
Benny W. Denham	82	Chairman and At-Large Director
Marshall S. Millwood	63	Vice-Chairman and At-Large Director
Bobby C. Smith, Jr.	59	At-Large Director
George L. Weaver	64	Member Group Director (group 1)
James I. White	67	Member Group Director (group 1)
Danny L. Nichols	48	Member Group Director (group 2)
Sammy G. Simonton	71	Member Group Director (group 2)
M. Anthony Ham	61	Member Group Director (group 3)
C. Hill Bentley	65	Member Group Director (group 3)
Fred A. McWhorter	66	Member Group Director (group 4)
Jeffrey W. Murphy	49	Member Group Director (group 4)
G. Randall Pugh	69	Member Group Director (group 5)
Wm. Ronald Duffey	71	Outside Director

(1) Currently, the second outside director position on our board of directors is vacant, and we have no current plans to elect a second 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 team. Each of our executive officers has 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.

Thomas A. Smith, our president and chief executive officer, is currently battling a serious illness. During his illness, Mr. Smith remains involved in our management and strategic direction and he continues to act in his capacity as president and chief executive officer. In order to provide Mr. Smith additional flexibility to focus on treating his health concerns, our executive vice presidents have expanded their roles and responsibilities in our day-to-day management and operations. Our board of directors is actively monitoring our leadership and management. Our board has a succession plan in place and is prepared to implement the plan, if necessary, to ensure that we continue to be managed in the best interests of our members.

Executive Officer Biographies

Thomas A. Smith is the President and Chief Executive Officer of Oglethorpe and has served in that capacity since September 1999. He previously served as our Senior Vice President and Chief Financial Officer from September 1998 to August 1999, Senior Financial Officer from 1997 to August 1998, Vice President, Finance from 1986 to 1990, Manager of Finance from 1983 to 1986 and Manager, Financial Services from 1979 to 1983. From 1990 to 1997, Mr. Smith was Senior Vice President of the Rural Utility Banking Group of CoBank. Mr. Smith has a Master of Science degree in Industrial Management-Finance from the Georgia Institute of Technology, a Master of Science degree in Analytical Chemistry from Purdue University, and a Bachelor of Arts degree in Mathematics and Chemistry from Catawba College. Mr. Smith is a Director of ACES Power Marketing. Mr. Smith is also a Director of the Electric Power Research Institute and is Chairman of its Audit Committee through April 2013. He is also a Director of the Georgia Chamber of Commerce and a member of the Georgia Tech Advisory Board. For the years 2007-2011, Mr. Smith was named to Georgia Trend's list of the top 100 most influential Georgians. In 2003, Mr. Smith was a recipient of the Ellis Island Medal of Honor.

Michael W. Price is our Executive Vice President and Chief Operating Officer and has served in that office since February 1, 2000. In October 2008, Mr. Price's title changed from Chief Operating Officer to his current title. Mr. Price was employed by Georgia System Operations from January 1999 to January 2000, first as Senior Vice President and then as Chief Operating Officer. He served as Vice President of System Planning and Construction of Georgia Transmission from May 1997 to December 1998. He served as a manager of system control of Georgia System Operations from January to May 1997. From 1986 to 1997, Mr. Price was employed by Oglethorpe in the areas of control room operations, system planning, construction and engineering, and energy management systems. Prior to joining Oglethorpe, he was a field test engineer with the Tennessee Valley Authority from 1983 to 1986. Mr. Price has a Bachelor of Science degree in Electrical Engineering from Auburn University. Mr. Price is a director of ACES Power Marketing, a director of National Renewables Cooperative Organization and a member of the Research Advisory Committee of the Electric Power Research Institute.

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 with high honors and a Master of Business Administration degree from Georgia State University.

William F. Ussery is our Executive Vice President, Member and External 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 his current title. 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 Drug, Inc. and previously served as Chairman of the Board.

W. Clayton Robbins is our Senior Vice President, Governmental Affairs and has served in the office since October 2008. Prior to that Mr. Robbins was Senior

Vice President, Government Relations and Chief Administrative Officer from July 2006 until October 2008, and as Chief Administrative Officer from January 2006 until July 2006. He also served as Senior Vice President, Administration and Risk Management of Oglethorpe from October 2002 to December 2006; and served as Senior Vice President, Finance and Administration of Oglethorpe from November 1999 to September 2002. Mr. Robbins served as Senior Vice President and General Manager of Intellisource, Inc. from February 1997 to October 1999. Prior to that, Mr. Robbins held several senior management and executive management positions at Oglethorpe beginning in 1986. Before joining Oglethorpe, Mr. Robbins spent 18 years with Stearns-Catalytic World Corporation, a major engineering and construction firm, including 13 years in management positions responsible for human resources, information systems, contracts, insurance, accounting, and project development. Mr. Robbins has a Bachelor of Arts degree in Business Administration from the University of North Carolina at Charlotte. Mr. Robbins serves as our director for the American Coalition for Clean Coal Electricity.

Charles W. Whitney is our Senior Vice President and General Counsel and has served in that capacity since August 2009. Mr. Whitney has legal experience that spans a broad range of activities in both private practice and as chief counsel to a nuclear generating plant project. He has represented independent power producers and engineering, procurement and construction contractors in the development, construction and operation of power projects in Georgia, New York, Pennsylvania, Ohio, Michigan and Wisconsin. In private practice, Mr. Whitney's areas of focus were energy, particularly nuclear energy, regulatory, construction and labor law. His practice has also included extensive work in labor and employment discrimination; certification, enforcement and rate-making proceedings before state and federal regulators; and general trial work. In addition to practicing law for 20 years, Mr. Whitney has more than ten years of experience in senior management in the electricity industry, including both the regulated and unregulated aspects of the business. Mr. Whitney is a graduate of Wright State University and earned his Juris Doctor degree from Case Western Reserve University School of Law.

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 has a Senior Professional in Human Resources certification.

Board of Directors

Director Qualifications

As required by our bylaws, all of the members of our board of directors, except for the independent 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; neither we nor our management has any 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

C. Hill Bentley is a member group director (group 3). Mr. Bentley has served on our board of directors since March 2004, and his present term will expire in March 2013. He is also a member of the audit committee. He is the Chief Executive Officer of Tri-County Electric Membership Corporation. He is on the Board of Directors of the Georgia Cooperative Council and a member of the board of directors of the Central Georgia Technical College Foundation. Mr. Bentley is a member of the Georgia Chamber of Commerce and is past President of the Jones County Chamber of Commerce. He serves on the Government Relations Committee for Georgia Electric Membership

Corporation. Mr. Bentley is a member, and a past President, of the Georgia Rural Electric Managers Association and chair of the Rural Electric Management Development Council. He was also appointed by the Governor to serve as a member of the Middle Georgia Regional Commission Council and is on the Business Advisory Council for Georgia College and State University.

Benny W. Denham is the Chairman of the Board and an at-large director. Mr. Denham has served on our board of directors since December 1988, and his present term will expire in March 2013. Mr. Denham has been co-owner of Denham Farms in Turner County, Georgia since 1980. Mr. Denham is a director of Irwin Electric Membership Corporation and a director of Georgia Electric Membership Corporation.

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 2015. He is also the chairman of the audit committee. 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 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 a director of Piedmont-Newnan Hospital and of Piedmont Healthcare, where he is chair of the audit and compliance committee and also serves on the executive committee. Mr. Duffey is also a member of the board of directors of the Georgia Chamber of Commerce.

M. Anthony Ham is a member group director (group 3). Mr. Ham has served on our board of directors since March 2004, and his present term will expire in March 2014. He is also a member of the compensation committee. Mr. Ham operates Tony Ham Elite Property Services. In December 2008, Mr. Ham left his position as the Clerk of the Superior and Juvenile Court in Brantley County, Georgia after 20 years of service. He is a director of Okefenoke Rural Electric Membership Corporation and was appointed Secretary and Treasurer in 2007.

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 2013. He is a member of the construction project committee. Mr. McWhorter serves as Vice Chairman of the Rayle Electric Membership Corporation board of directors. Mr. McWhorter also serves on the board of directors for Georgia Electric Cooperative. He works for the U.S. Postal Service and is owner of F.A. McWhorter Poultry Farms.

Marshall S. Millwood is the Vice-Chairman of the Board and an at-large director. Mr. Millwood has served on our board of directors since March 2003, and his present term will expire in March 2015. He is also the chairman of the compensation committee. 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 2015. He is also 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 the 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 2014. Mr. Nichols is a member of the construction project committee. Mr. Nichols is the General Manager of Colquitt Electric Membership Corporation.

G. Randall Pugh is a member group director (group 5). Mr. Pugh has served on our board of directors since May 2008, and his present term will expire in March 2014. He is also the chairman of the construction project committee. Mr. Pugh is the President and Chief Executive Officer of Jackson Electric Membership Corporation, prior to which he served as General Manager of Walton Electric Membership Corporation. From 2006 to 2011, Mr. Pugh was on the Board of First Georgia Banking Company (Jackson and Banks County) and from 2007 to 2011, he served on the Board of Directors of First Georgia

Bankshares Holding Company. He serves on the board of directors for Georgia System Operations and is Chairman of the Audit Committee and also serves as Secretary-Treasurer. He also serves on the Board of Directors of Green Power Electric Membership Corporation. Mr. Pugh is a member of the Executive Board of the Northeast Georgia Council of the Boy Scouts of America. He also is a member and past President of the Jackson County Chamber of Commerce and of the Jefferson Rotary Club.

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 2015. He is also a member of the compensation 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.

Bobby C. Smith, Jr. is an at-large director. Mr. Smith has served on our board of directors since May 2008, and his present term will expire in March 2014. He is also a member of the construction project committee. Mr. Smith is a farmer. He is a member of the board of directors of Planters Electric Membership Corporation. He is also Chairman of the board of the Screven County Development Authority and a member of the Sylvania Lions Club.

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 2013. He is a member of the compensation committee. Mr. Weaver has been employed by Central Georgia Electric Membership Corporation since 1970 and is currently serving as President. Mr. Weaver is currently a director of Southeastern Data Cooperative and is a former director of First Georgia Community Corporation and Federated Rural Electric Insurance Corporation.

James I. White is 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 2014. 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 is also a member of the Henry County Chamber of Commerce and 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 all material aspects of our financial reporting functions. Its responsibilities 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 members of the audit committee are currently Ronald Duffey, Jeffrey Murphy, Hill Bentley 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 its compensation programs as needed. Currently, the members of the compensation committee are Marshall Millwood, Anthony Ham and George Weaver. Mr. Millwood 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. The members of the construction project committee are currently Randall Pugh, Fred McWhorter, Danny Nichols and Bobby Smith. Mr. Pugh 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. Management also develops and typically shares a corporate risk map with our board of directors during this session. The corporate risk map depicts the probability of occurrence and the potential severity for each significant corporate risk. 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.

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 as well as discussing 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 and environmental compliance and electric reliability compliance. 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 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 as a check 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, 2012 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.

Each of our executive officers has 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 our strategic, operational and financial goals. The corporate goals selected are designed to align the interests of our executive team 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. Each executive officer is eligible to receive up to 20% of his or her base salary as a performance bonus based entirely on the achievement of corporate goals.

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 all 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 its 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 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, and will contribute an additional amount equal to 8% 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 determines the bonus criteria and may issue discretionary bonuses to our president and chief executive officer. Our president and chief executive officer determines the bonus criteria and may 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. 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 currently reviews and sets the compensation 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.

The compensation committee also approves our performance pay program, including the corporate goals related to such program. Bonuses for the president and chief executive officer are also at the discretion of the compensation committee. The compensation committee receives a comprehensive report on an annual basis regarding all facets of our compensation program. The compensation committee also reviews the employment contracts each year and makes an affirmative decision whether they 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 our other employees. The compensation committee annually reviews the 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 upward adjustment to the executive officers' base salary. Our president and chief executive officer reports the executive officers' salaries to the compensation committee annually. 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, 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. These approvals include the compensation of our president and chief executive officer and the components of our compensation program each year.

Role of Generally Available Market Data. To confirm that our compensation remains competitive, we review standardized surveys to check our total compensation program against other companies in the utility industry of a similar size. We do not benchmark against such data; rather 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 we have not hired a compensation consultant to provide us with information on executive compensation data. Compensation levels other companies pay to their executives do not drive our compensation decisions, and we do not target a specific market percentile for our executive officer 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 2012, our performance measures were divided into the following categories: i) operations, ii) financial, iii) quality, iv) corporate compliance and v) safety. 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.

The maximum performance pay each executive officer can receive is 20% of his or her salary and in order to receive the full 20%, 100% of the performance measures must be achieved. The performance measures are weighted to align with our current strategic focus, and each goal is reviewed annually, and adjusted if necessary 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:

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 start reliability and equivalent forced outage rate are measured against industry averages and the applicable thresholds are set above average. In order to meet these standards, we must properly operate and maintain these facilities, which minimizes long-term maintenance and replacement energy costs. Certain operational goals take into account performance standards as required by contracts related to the facility operations. This corporate goal excludes performance measures related to facilities operated by Georgia Power as we do not direct operations at those facilities. Our achieving operational excellence at the corporate level results in the most reliable, efficient and lowest cost power supply for our members.

Financial. Our financial goals are divided into two components, (i) a cost savings and reduction goal and (ii) a value added and risk reduction goal. The cost savings and reduction 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 in the long-term. Any cost savings included in this goal must be over and above what would generally be expected. The value added and risk reduction goal encourages staff to develop programs that add value to our resources and reduce risk exposure. Some of these programs are subjective and not readily quantifiable in dollar terms and therefore discretion as to the achievement of the value added component is placed with the compensation committee. Our financial goals provide direct benefits to our members by lowering power costs and adding value to our assets.

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.

Corporate Compliance. Our corporate compliance goals are divided into three categories – environmental, electric reliability standards and enhancement of our corporate compliance program. The environmental goals incentivize 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 considering whether we have received notice of any violations from electric reliability organizations. To achieve the maximum awards for the environmental and reliability categories, we must achieve perfection, meaning no spills or notices of violation. Our corporate compliance program was designed to minimize business risks related to non-compliance with general laws, rules and regulations, contracts and other business concerns and minimize any economic consequences. The related goal measures our performance enhancing and strengthening this program.

Safety. Our safety goals provide employees a financial incentive to focus on a safe workplace environment, which increases employee morale and minimizes lost time. Safety performance is measured by comparing incident rates in our work environment against national incident rates compiled by the U.S. Department of Labor's Bureau of Labor Statistics.

Calculation of Performance Pay Earned

Performance pay earned by our executive officers is based entirely 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 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 each executive officer, we multiply 20% of his or her base salary by the achievement percentage to determine his or her performance bonus. For example, if we had a 90% corporate goal achievement rate in a given year, each executive officer's performance bonus would equal (base salary $\times$ 20%) $\times$ (90%).

Assessment of Performance of 2012 Corporate Goals

The specific corporate performance measures, thresholds, maximums and results for our executive officers' 2012 performance pay were the following:

Performance Category/Description	Performance Measure	Threshold	Maximum	2012 Result	Weight	Weighted Goal Achieved
Operations(1)						
Rocky Mountain	Start Reliability	99.9%	100.0%	100.0%	3.0%	3.0%
	Peak Season Availability	94.0%	100.0%	100.0%	4.0%	4.0%
	Equivalent Forced Outage Rate	1.8%	0.0%	0.1%	4.0%	4.0%
Combustion Turbine	Start Reliability	98.7-100.0%	100.0%	97.4%	4.0%	1.9%
Operations	Peak Season Availability	98.1-98.6%	100.0%	97.4%	9.0%	6.8%
Chattahoochee	Availability	96.5-98.0%	100.0%	98.5%	4.0%	2.9%
	Dispatch Order Percentage	95.0%	100.0%	96.3%	3.0%	1.3%
Smith	Seasonable Availability Percentage	95.5-97.0%	99.0-100.0%	99.3%	1.0%	1.0%
	Profitability	$ 5,000,000	$ 15,000,000	$ 14,701,350	2.0%	2.0%
	Peak Season Availability	96.8%	100.0%	98.2%	1.0%	0.7%
	Dispatch Order Percentage	95.0%	100.0%	98.2%	1.0%	0.7%
Financial						
Cost Savings/Reduction Programs and Activities	Current-Year Savings	$ 1,000,000	$ 10,000,000	$ 17,437,282	10.0%	10.0%
	Long-Term Savings	$ 5,000,000	$ 35,000,000	$ 34,695,669	10.0%	9.9%
Value Added/Risk Reduction	Qualifying Programs	0	3	3	3.0%	3.0%
Quality						
Board Satisfaction	Board of Directors Survey	80.0%	100.0%	95.3%	20.0%	16.5%
Corporate Compliance						
Environmental	Final Notices of Violation	1 (if fine is less than $5,000)	0	0	3.0%	3.0%
	Letters of Non-Compliance	2	0	0	2.0%	2.0%
	Reportable Spills	0	0	0	2.5%	2.5%
	Non-Reportable Spills	1 (if less than $5,000 to clean-up)	0	1	1.5%	0.0%
Electric Reliability Standards	Mandatory Electric Reliability Standard	1 (if penalty is $25,000 or less)	0	0	2.0%	2.0%
	Electric Reliability Program Enhancements	100.0%	100.0%	100.0%	1.0%	1.0%
Corporate Compliance Enhancement Program	Code of Conduct Training	100.0%	100.0%	100.0%	1.0%	1.0%
	Compliance Risk Assessment	100.0%	100.0%	100.0%	1.0%	1.0%
	Compliance Assurance Review Plan	75.0%	100%	100.0%	1.0%	1.0%
Safety						
Quality of Safety	Number of Recordable Injuries and Illnesses	4	0	1	1.5%	1.1%
	Number of Lost Work Cases	2	0	0	1.5%	1.5%
	Maintain Rural Electric Safety Accreditation	Yes	Yes	Yes	1.0%	1.0%
	World Class Safety Development	100.0%	100.0%	100.0%	2.0%	2.0%
Total					**100.0%**	**86.8%**

(1) Operations goals apply to individual units of each generation facility. The thresholds and performance results provided in this summary table are aggregated results based on all of the generating units within the category.

As noted above, we achieved 86.8% of our corporate goals for 2012. As a result of achieving 86.8% of our corporate goals, each of our executive officers received performance pay in an amount equal to 86.8% of 20% of his or her base salary. Set forth below is a table showing 2012 performance pay figures for each of our executive officers:

Executive Officer	Performance Pay*
Mr. Smith	$ 107,285
Mr. Price	62,111
Ms. Higgins	62,111
Mr. Ussery	47,885
Mr. Whitney	54,983

* Performance pay was calculated based on base salaries as of December 31, 2012. Actual compensation earned in 2012 is reported in the Summary Compensation Table below.

Employment Agreements

General

We have an employment agreement with each of our executive officers. 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 our executive officers' goals are aligned with our members' and that each performs his or her respective role while acting solely in our members' best interests. The compensation committee reviews these agreements annually and last reviewed these employment agreements in November 2012.

We entered into our current employment agreement with Mr. Smith on January 1, 2007. Pursuant to the automatic renewal provision of his employment agreement, the current term of the agreement extends through December 31, 2015 and will continue to automatically renew for successive one-year periods unless either party provides written notice not to renew the agreement twenty-five months before the expiration of any extended term. No such notice has been provided. Mr. Smith's minimum annual base salary under his agreement is $440,870, and is subject to review and upward adjustment by our board of directors. Mr. Smith is eligible for an annual bonus and to participate in incentive compensation plans generally available to similarly situated employees, 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. Details regarding the severance pay provisions of the agreement are provided under "– Severance Arrangements."

We also have employment agreements with Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney. Pursuant to the automatic renewal provisions of these employment agreements, the current term of each agreement extends through December 31, 2014 and will continue to automatically renew for successive one-year periods unless either party provides written notice not to renew the agreement thirteen months before the expiration of any extended term. No such notices have been provided.

Minimum annual base salaries under these agreements are $255,116 for Mr. Price, $246,887 for Ms. Higgins, $171,700 for Mr. Ussery, and $300,000 for Mr. Whitney. Salaries are subject to review and possible adjustment as determined by the president and the chief executive officer. Each executive is also eligible for an annual bonus and to participate in incentive compensation plans generally available to similarly situated employees, determined by us in our sole discretion. The employment agreements with Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney contain severance pay provisions. Details regarding the severance pay provisions of the agreements are provided under "– Severance Arrangements" below.

Assessment of Severance Arrangements

Pursuant to their respective employment agreements, each of our executive officers is entitled to certain 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 it 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 considered 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 executives to accumulate large amounts of wealth during employment.

The compensation committee also considered the total amount of compensation each of the other executive officers would receive upon the occurrence of a severance event. The compensation committee determined that it was appropriate for our other executive officers to receive severance compensation equal to one year's compensation, plus benefits as described below, because such agreements provide a measure of stability for both us and our other executive officers. In addition, like our president and chief executive officer, our other executive officers are not compensated using options or other forms of equity compensation that lead to significant wealth accumulation. Therefore, the compensation committee believed such severance compensation is necessary to address competitive concerns and offset any potential risk our executive officers face in the course of their employment.

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, 2012 for filing with the SEC.

Respectfully Submitted,

The Compensation Committee

M. Anthony Ham
Marshall S. Millwood
George L. Weaver

Compensation Committee Interlocks and Insider Participation

Marshall S. Millwood, J. Sam L. Rabun, M. Anthony Ham, Larry N. Chadwick, and George L. Weaver served as members of our compensation committee in 2012.

Mr. Weaver is a director of ours and also the president of Central Georgia Electric Membership Corporation. Central Georgia is a member of ours and has a wholesale power contract with us. Central Georgia's payments of $31 million to us in 2012 under its wholesale power contract accounted for 2.4% 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, 2012, 2011 and 2010.

Name and Principal Position	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	All Other Compensation(1)	Total
Thomas A. Smith	2012	$ 615,009	$ –	$ 107,285	$ 96,604	$ 818,898
President and Chief Executive Officer	2011	595,792	–	96,840	98,681	791,313
	2010	575,030	50,000	101,386	92,965	819,381
Michael W. Price	2012	356,044	10,000	62,111	62,334	490,489
Executive Vice President and Chief Operating Officer	2011	345,133	–	56,064	62,660	463,857
	2010	334,000	6,680	58,918	53,207	452,805
Elizabeth B. Higgins	2012	356,044	10,000	62,111	54,588	482,743
Executive Vice President and Chief Financial Officer	2011	345,133	–	56,064	53,726	454.923
	2010	334,000	6,680	58,918	52,243	451,841
William F. Ussery	2012	274,495	10,000	47,885	50,925	383,305
Executive Vice President, Member and External Relations	2011	266,500	–	43,223	44,470	354,193
	2010	260,124	–	45,864	43,568	349,556
Charles W. Whitney	2012	315,188	–	54,983	58,350	428,521
Senior Vice President, General Counsel	2011	306,250	–	49,631	57,080	412,961
	2010	300,144	–	52,920	31,664	384,728

(1) Figures for 2012 consist of customary holiday gifts, service awards, matching contributions made by Oglethorpe under the 401(k) Retirement Savings Plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney of $11,250, $11,250, $11,250, $9,073 and $11,250, respectively; contributions made by Oglethorpe under the 401(k) Retirement Savings Plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney of $20,000, $20,000, $20,000, $20,000 and $20,000, respectively; contributions by Oglethorpe to a nonqualified deferred compensation plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney, respectively of $37,871, $13,503, $12,969, $5,829 and $9,185; a car allowance of $12,000, $9,000, $9,000, $9,000 and $9,000 for Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney, respectively; and insurance premiums paid on term life insurance on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney of $3,870, $1,826, $794, $1,798 and $8,840, respectively and payment for unused paid time off for Mr. Smith, Mr. Price and Mr. Ussery in the amount of $11,538, $6,680 and $5,150, respectively.

The following table sets forth the threshold, or minimum, and maximum awards available to the executive officers listed in the Summary Compensation Table with respect to performance pay for the fiscal year ended December 31, 2012.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards	
Name	**Grant Date**	**Threshold**	**Maximum**
Thomas A. Smith President and Chief Executive Officer	N/A	$ 24,423	$ 123,600
Michael W. Price Executive Vice President and Chief Operating Officer	N/A	14,139	71,566
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	N/A	14,139	71,556
William F. Ussery Executive Vice President, Member and External Relations	N/A	10,901	55,167
Charles W. Whitney Senior Vice President and General Counsel	N/A	12,517	63,345

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 2012 Corporate Goals*."

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 ($250,000 as indexed).

From 2001 through 2004, Mr. Smith received deferred compensation benefits through his participation in our Executive Supplemental Retirement Plan. Mr. Smith has not received any benefits pursuant to this plan since 2004 and none of our other executive officers are currently participating in this plan.

The following table sets forth our contributions for the fiscal year ended December 31, 2012 along with aggregate earnings for the same period.

Name	Registrant Contributions in Last FY(1)	Aggregate Earnings in Last FY(2)	Aggregate Balance at Last FYE
Thomas A. Smith President and Chief Executive Officer	$ 37,871	$ 49,528	$ 610,669
Michael W. Price Executive Vice President and Chief Operating Officer	13,503	9,731	92,400
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	12,969	12,192	89,861
William F. Ussery Executive Vice President, Member and External Relations	5,829	3,683	28,647
Charles W. Whitney Senior Vice President and General Counsel	9,185	1,050	19,539

(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.

Severance Arrangements

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, 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 within 45 days after his termination date. The maximum severance that would be payable to Mr. Smith in the circumstances described above is $1,356,018.

Pursuant to the terms of their employment agreements, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney 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 one year of the executive's then current base salary, payable six months after the executive's termination date. In addition, the executive will be entitled to six months of outplacement services and an amount equal to the executive's cost for medical and dental continuation coverage under COBRA for six months. Severance is payable only if the executive signs a form releasing all claims against us within 45 days after his or her termination date. The maximum severance that would be payable to Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney in the circumstances described above is $396,461, $396,500, $302,356 and $349,066, respectively.

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, 2012.

Name	Total Fees Earned or Paid in Cash
Member Directors	
Benny W. Denham, Chairman	$ 19,620
Marshall S. Millwood, Vice-Chairman	$ 18,700
C. Hill Bentley	$ 16,000
Larry N. Chadwick	$ 2,000(1)
M. Anthony Ham	$ 16,000
Fred A. McWhorter	$ 6,400
Jeffrey W. Murphy	$ 16,000
Danny L. Nichols	$ 16,100
G. Randall Pugh	$ 12,100(2)
J. Sam L. Rabun	$ 8,400(3)
Sammy G. Simonton	$ 5,500
Bobby C. Smith, Jr.	$ 17,300
George L. Weaver	$ 14,800
James I. White	$ 16,500
H.B. Wiley, Jr.	$ 8,100(4)
Outside Director	
Wm. Ronald Duffey	$ 36,300

(1) On March 1, 2012, Mr. Chadwick resigned from his position on the board of directors of Cobb Electric Membership Corporation and became ineligible to serve on our board of directors.

(2) Mr. Pugh's compensation is paid directly to Jackson Electric Membership Corporation, where he serves as President and Chief Executive Officer.

(3) On July 17, 2012, Mr. Rabun's term as a member of the board of directors of Jefferson Energy Cooperative ended and he became ineligible to serve on our board of directors.

(4) On August 31, 2012, Mr. Wiley passed away.

During 2012, we paid our member directors a fee of $1,200 per board meeting and $800 per day for attending committee meetings, other meetings, or other official business approved by the chairman of the board of directors. Member directors are paid $600 per day for attending the annual meeting of members and member advisory board meetings. Our outside director was paid 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 other 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 are paid $100 per day 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. Neither our outside director nor member directors receive any perquisites or other personal benefits from us.

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

Hill Bentley is a director of ours and the Chief Executive Officer of Tri-County Electric Membership Corporation. Tri-County is a member of ours and has a wholesale power contract with us. Tri-County's revenues of $13.8 million to us in 2012 under its wholesale power contract accounted for approximately 1.0% 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 $19.4 million to us in 2012 under its wholesale power contract accounted for approximately 1.5% 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 $37.2 million to us in 2012 under its wholesale power contract accounted for approximately 2.8% of our total revenues.

Randall Pugh 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 $157.4 million to us in 2012 under its wholesale power contract accounted for approximately 11.9% of our total revenues.

George Weaver is a director of ours and the President 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 $31.0 million to us in 2012 under its wholesale power contract accounted for approximately 2.4% 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, the 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 Randall Pugh, satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet the requirements set forth in our bylaws. Randall Pugh does not qualify as an independent director because he is the President and Chief Executive Officer of Jackson, which accounted for approximately 11.9% of our revenues for the fiscal year ended December 31, 2012. 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 2012 and 2011, fees for services provided by our independent registered public accounting firm, Ernst & Young LLP were as follows:

	2012	2011
	(dollars in thousands)	
Audit Fees[1]	**$ 586**	$ 548
Audit-Related Fees[2]	**2**	2
Tax Fees[3]	**36**	25
Total	**$ 624**	$ 575

(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.

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 2012 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.

(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 May 1, 2008 (Updated on May 1, 2010 to reflect SMG membership change). (Filed as Exhibit 3.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010, File No. 000-53908.)
*4.1	–	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.)

*4.2(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.)
*4.2(b)	–	First Supplement to Lease Agreement No. 2 (included as Exhibit B to the Supplemental Participation Agreement No. 2 listed as 10.1.1(b)).
*4.2(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.)
*4.2(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.)
*4.3	–	Seventh Amended and Restated Loan Contract, dated as of April 15, 2011, between Oglethorpe and the United States of America, together with four notes executed and delivered pursuant thereto. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)

*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)

*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)

*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)

*4.4.1(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.)
*4.4.1(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(qq) to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)

*4.4.1 (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.)
*4.4.1 (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.)
*4.4.1 (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.)
*4.4.1 (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.)
*4.4.1 (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.)
*4.4.1 (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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)

*4.4.1(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.)
*4.4.1(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.)
*4.4.1(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.)
*4.4.2	–	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.)
*4.5	–	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.)
4.6.1[(1)]	–	Loan Agreement, dated as of August 1, 2008, between Development Authority of Burke County and Oglethorpe relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2008A, and three other substantially identical (Fixed Rate Bonds) loan agreements.
4.6.2[(1)]	–	Note, dated August 27, 2008, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of August 1, 2008, between Development Authority of Burke County and U.S. Bank National Association relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2008A, and three other substantially identical notes.
4.6.3[(1)]	–	Trust Indenture, dated as of August 1, 2008, between Development Authority of Burke County and U.S. Bank National Association, as trustee, relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2008A, and three other substantially identical indentures.
4.7.1[(1)]	–	Loan Agreement, dated as of December 1, 2003, between Development Authority of Burke County and Oglethorpe relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2003A, and seven other substantially identical (Auction Rate Bonds) loan agreements.
4.7.2[(1)]	–	Note, dated December 3, 2003, from Oglethorpe to SunTrust Bank, as trustee, pursuant to a Trust Indenture, dated December 1, 2003, between Development Authority of Burke County and SunTrust Bank relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2003A, and seven other substantially identical notes.
4.7.3[(1)]	–	Trust Indenture, dated as of December 1, 2003, between Development Authority of Burke County and SunTrust Bank, as trustee, relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2003A, and seven other substantially identical indentures.

4.8.1[(1)]	–	Loan Agreement, dated as of December 1, 2009, between Development of Monroe County and Oglethorpe relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical (Variable Rate Bonds) loan agreements.
4.8.2[(1)]	–	Note, dated December 1, 2009, from Oglethorpe to U.S. Bank National Association, as trustee, pursuant to a Trust Indenture, dated December 1, 2009, between Development Authority of Monroe County and U.S. Bank National Association relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical notes.
4.8.3[(1)]	–	Trust Indenture, dated December 1, 2009, between Development Authority of Monroe County and U.S. Bank National Association, as trustee, relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical indentures.
4.9.1[(1)]	–	Master Loan Agreement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, MLA No. 0459.
4.9.2[(1)]	–	Consolidating Supplement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, relating to Loan No. ML0459T1.
4.9.3[(1)]	–	Promissory Note, dated March 1, 1997, in the original principal amount of $7,102,740.26, from Oglethorpe to CoBank, ACB, relating to Loan No. ML0459T1.
4.9.4[(1)]	–	Consolidating Supplement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, relating to Loan No. ML0459T2.
4.9.5[(1)]	–	Promissory Note, dated March 1, 1997, in the original principal amount of $1,856,475.12, made by Oglethorpe to CoBank, ACB, relating to Loan No. ML0459T2.
4.10.1[(1)]	–	Committed, Revolving Credit Facility Agreement, dated as of August 1, 2009, between Oglethorpe and National Rural Utilities Cooperative Finance Corporation, relating to the Series 2009B CFC Note.
4.10.2[(1)]	–	Series 2009B CFC Note, dated August 11, 2009, in the original principal amount of $250,000,000, from Oglethorpe to National Rural Utilities Cooperative Finance Corporation.
4.10.3[(1)]	–	Term Loan Agreement, dated as of August 1, 2009, between Oglethorpe and National Rural Utilities Cooperative Finance Corporation, relating to the Series 2009C Note.
4.10.4[(1)]	–	Series 2009C CFC Note, dated August 11, 2009, in the original principal amount of $250,000,000, from Oglethorpe to National Rural Utilities Cooperative Finance Corporation.
4.11.1[(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).
4.11.2[(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.
*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(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.)
*10.1.3(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.)
*10.1.3(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.)
*10.1.4(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.)
*10.1.4(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.)

*10.1.4(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.)
*10.1.5(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.)
*10.1.5(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.)
*10.1.6	–	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.)
*10.1.7(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.)
*10.1.7(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.)
*10.2.3	–	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.)
*10.3.3	–	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 April 27, 2006, File No. 33-7591.)
10.3.4(a)[2]	–	Engineering, Procurement and Construction Agreement between Georgia Power Company, acting for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, as owners and a consortium consisting of Westinghouse Electric Company LLC and Stone & Weber, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, dated as of April 8, 2008. (Incorporated by reference to Exhibit 10(c)1 of Georgia Power Company's Form 10-Q/A for the quarterly period ended June 30, 2008, filed with the SEC on January 26, 2009.)
10.3.4(b)[2]	–	Amendment No. 1, dated as of December 11, 2009, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)29 of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2009, filed with the SEC on February 25, 2010.)
10.3.4(c)[2]	–	Amendment No. 2, dated as of January 15, 2010, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(1) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2010, filed with the SEC on May 7, 2010.)
10.3.4(d)[2]	–	Amendment No. 3, dated as of February 23, 2010, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2010, filed with the SEC on May 7, 2010.)
*10.4.1	–	Plant Hal Wansley Purchase and Ownership Participation Agreement between Georgia Power Company and Oglethorpe, dated as of March 26, 1976. (Filed as Exhibit 10.8.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.4.2(a)	–	Plant Hal Wansley Operating Agreement between Georgia Power Company and Oglethorpe, dated as of March 26, 1976. (Filed as Exhibit 10.8.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.4.2(b)	–	Amendment, dated as of January 15, 1995, to the Plant Hal Wansley Operating Agreements by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.5.2(a) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1996, File No. 33-7591.)

*10.4.3	–	Plant Hal Wansley Combustion Turbine Agreement between Georgia Power Company and Oglethorpe, dated as of August 2, 1982 and Amendment No. 1, dated October 20, 1982. (Filed as Exhibit 10.18 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.5.1	–	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.)
*10.5.2	–	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.)
*10.6.1	–	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.)
*10.6.2	–	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.)
*10.7.1	–	Amended and Restated Wholesale Power Contract, dated as of January 1, 2003, between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 37 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.)
*10.7.2	–	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 36 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.)
*10.7.3	–	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 37 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.)
*10.7.4	–	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 37 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.)
*10.7.5	–	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.)
*10.7.6	–	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.)

*10.8	–	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.)
*10.9	–	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.)
*10.10	–	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.)
*10.11.1(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.)
*10.11.1(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 Electric 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.)
*10.11.2	–	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.)
*10.11.3	–	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.)
*10.12	–	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.)
*10.13	–	Credit Agreement, dated as of June 9, 2011, among Oglethorpe, as borrower, and the lenders identified therein, including Bank of America, N.A., as administrative agent (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed June 10, 2011, File No. 000-53908.)
*10.14[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and Thomas A. Smith. (Filed as Exhibit 10.19 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.15[3]	–	Employment Agreement, dated January 1, 2007, between Oglethorpe and Michael W. Price. (Filed as Exhibit 10.20 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.16[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and Elizabeth Bush Higgins. (Filed as Exhibit 10.21 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.17[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and William F. Ussery. (Filed as Exhibit 10.23 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)

*10.18[3]	–	Employment Agreement, dated as of August 17, 2009, between Oglethorpe and Charles W. Whitney (Filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2009, File No. 33-7591.)
*10.19	–	Oglethorpe Power Corporation Executive Incentive Payment Plan, dated November 8, 2007. (Filed as Exhibit 10.25 to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.)
*10.20	–	Participation Agreement for the Oglethorpe Power Corporation Executive Supplemental Retirement Plan, dated as of March 15, 2002, between Oglethorpe and Thomas A. Smith. (Filed as Exhibit 10.30 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2002, File No. 33-7591.)
12.1	–	Oglethorpe Computation of Ratio of Earnings to Fixed Charges, Margins for Interest Ratio and Equity Ratio
14.1	–	Code of Conduct, last revised July 25, 2011, available on our website, www.opc.com.
23.1	–	Consent of Ernst & Young LLP
31.1	–	Rule 13a-14(a)/15d-14(a) Certification, by Thomas A. 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 Thomas A. 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, 2012, File No. 000-53908.)
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 22nd day of March, 2013.

OGLETHORPE POWER CORPORATION
(AN ELECTRIC MEMBERSHIP CORPORATION)

By: /s/ THOMAS A. SMITH

THOMAS A. 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/ THOMAS A. SMITH THOMAS A. SMITH	President and Chief Executive Officer (Principal Executive Officer)	March 22, 2013
/s/ ELIZABETH B. HIGGINS ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 22, 2013
/s/ G. KENNETH WARREN, JR. G. KENNETH WARREN, JR.	Vice President, Controller (Principal Accounting Officer)	March 22, 2013
/s/ C. HILL BENTLEY C. HILL BENTLEY	Director	March 22, 2013
/s/ BENNY W. DENHAM BENNY W. DENHAM	Director	March 22, 2013
/s/ WM. RONALD DUFFEY WM. RONALD DUFFEY	Director	March 22, 2013
/s/ M. ANTHONY HAM M. ANTHONY HAM	Director	March 22, 2013
/s/ FRED MCWHORTER FRED MCWHORTER	Director	March 22, 2013

Signature	Title	Date
/s/ MARSHALL S. MILLWOOD MARSHALL S. MILLWOOD	Director	March 22, 2013
/s/ JEFFREY W. MURPHY JEFFREY W. MURPHY	Director	March 22, 2013
/s/ DANNY L. NICHOLS DANNY L. NICHOLS	Director	March 22, 2013
/s/ G. RANDALL PUGH G. RANDALL PUGH	Director	March 22, 2013
/s/ SAMMY G. SIMONTON SAMMY G. SIMONTON	Director	March 22, 2013
/s/ BOBBY C. SMITH, JR. BOBBY C. SMITH, JR.	Director	March 22, 2013
/s/ GEORGE L. WEAVER GEORGE L. WEAVER	Director	March 22, 2013
/s/ JAMES I. WHITE JAMES I. WHITE	Director	March 22, 2013