ANNUAL REPORT 2021

santee cooper®

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Letter from the Chairman and CEO

On June 8, 2021, the South Carolina General Assembly gave Santee Cooper a fresh start. Legislators spent four years studying options, consulting with customers and industry experts, and considering offers by private utilities to purchase Santee Cooper. Based on that extensive evaluation, legislators chose to retain state ownership of the utility as the best option for customers, but with significant new requirements for governance and oversight.

In terms of governance, Act 90 redefines Board member terms and requirements, provides a phased schedule for current directors to rotate off the Board, and adds two non-voting ex-officio members representing Central Electric Power Cooperative, Santee Cooper's largest customer.

In terms of oversight, Act 90 requires legislative approval of certain debt and property transactions and of compensation for the CEO. It requires annual reports to other legislative entities, and regular and defined oversight by the Public Service Commission and the Office of Regulatory Staff. The Public Service Commission, for example, must review and approve a triennial Integrated Resource Plan, power purchase contracts exceeding 10 years, a competitive procurement process for renewable generation, and actions related to construction or acquisition of major facilities. The Office of Regulatory Staff participates in our retail rate process and is entitled to appeal rate adjustments, has the authority to inspect, audit and examine documents and facilities, and comments on an annual pricing report.

Santee Cooper understands the value of these new governance and oversight measures, and we embrace our responsibilities in each area.

Act 90 does give Santee Cooper the operating flexibility to continue producing reliable and affordable electricity and water for customers, with a priority on safety and while also promoting environmental stewardship and economic development – the things we have done well for decades. These are primary responsibilities in our mission to be a leading resource for improving the lives of all South Carolinians.

Santee Cooper's Board of Directors retains sole ratemaking authority, which keeps us compliant with existing bond covenants.

As we closed out 2021, the Board hired a new President and CEO to replace Mark Bonsall, who returned to retirement on Jan. 10, 2022. Jimmy Staton, a utility executive with extensive experience in electric and natural gas operations in the Midwestern United States, takes the helm on March 1. Deputy CEO Charlie Duckworth stepped in as Acting President and CEO in the interim. Staton comes to Santee Cooper from Southern Star Corp., a leading transporter of natural gas in the Midwest, where he was also President and CEO. Staton has also served as executive vice president for NiSource, one of the largest fully regulated utility companies in the United States with approximately 3.5 million natural gas customers and 500,000 electric customers across seven states; as senior vice president for Dominion Resources Inc.; and as president of asset operations for Consolidated Natural Gas (CNG) Corp. prior to its acquisition in 2000 by Dominion Resources. We look forward to him joining the Santee Cooper team.

Transparency and Engagement

Key in 2021, Santee Cooper began the planning to update our 2020 Integrated Resource Plan. Santee Cooper has filed a plan regularly with the state Office of Regulatory Staff. Act 90 requires additional steps in developing that plan, including a formal stakeholder engagement process. An Integrated Resource Plan details how Santee Cooper intends to meet the projected load of our customers while balancing multiple objectives, including system reliability, environmental responsibility, cost impacts and risks.

Our Board voted in 2021 to retire Winyah Generating Station by the end of 2028 as part of developing a leaner, greener generating portfolio. We worked with Central to identify solar developers who will bring 425 MWs to our combined system by the end of 2023, and we each issued contracts with those developers for our load share of the total. We are working with Central, in accordance with our Coordination Agreement, to evaluate options for a major new generating resource to replace Winyah and meet additional growth by the late 2020s. We are also planning additional solar beyond 2023, as well as demand side management and battery storage. All of this will be vetted through the IRP stakeholder process. We intend to have several public input meetings for all stakeholders to come and learn, ask questions and provide input. The first meeting will be in the March 2022.

Another key initiative in 2021 was to improve the diversity among Santee Cooper's suppliers. We have consistently ranked at the top of large state agencies when it comes to achieving a diverse workforce. We understand the importance of expanding that philosophy. We partnered with the Carolinas-Virginia Minority Supplier Development Council (CVMSDC) and in November hosted an inaugural Supplier Diversity Fair to help suppliers learn more about Santee Cooper, our upcoming procurement opportunities and how to do business with us, as well as to help eligible vendors become certified as minority-owned, women-owned or veteran-owned businesses. Because of this initiative, we added more diverse businesses to our supplier pool, and also identified current minority, women or veteran-owned suppliers who weren't listed that way. We will continue in 2022 to increase our business with a more diverse supplier pool.

Financial

Santee Cooper has "A"-category credit and stable outlooks from the three major credit rating agencies, following S&P's decision to upgrade its outlook to stable in August 2021.

The year brought challenges in the fuels area, as it did to most utilities in the country, with COVID-19 effects hindering rail transport of coal, a safety incident causing a prolonged shutdown at our largest coal supplier, significant increases in natural gas prices, and a fire interrupting output at the V.C. Summer Nuclear Station for several weeks. Our natural gas hedges mitigated costs for anticipated load, but we also saw an increase in customer demand that created additional pricing pressures. Santee Cooper is operating in a rate lock through 2024 and could not reflect these fuel prices in customer bills, and so we managed operating expenses where we could and made other adjustments to weather the challenges.

We also continued to execute strategies to reduce debt and the cost of debt. In September Santee Cooper closed on a $430 million bond sale that refunded $174 million of existing debt at lower interest rates (achieving net present value savings of $50 million), converted approximately $190 million in short-term, variable debt to fixed-rate debt at a low interest rate, and provided $160 million to use toward future capital projects and debt issuance costs. We also began preparing a larger tender/exchange offer of up to $2.7 billion in bonds and worked closely with the Joint Bond Review Council through the end of 2021 to move that initiative forward, receiving JBRC approval in early January 2022 to proceed to market and closing on the transaction in February 2022.

We finished 2021 with $56.3 million in reinvested earnings, debt service coverage of 1.27, and a debt/equity ratio of 76/24, all prior to our annual payment to the state.

Safety

Santee Cooper had our best safety year ever in 2021, with just six recordable incidents and two preventable motor vehicle accidents. By looking out for each other, the Santee Cooper team improved an already exceptional safety record. Santee Cooper earned the American Public Power Association's Safety Award of Excellence four times between 2016 and 2020, and although the results for 2021 are not yet available, our team is in a good position to receive it again for 2021.

Customer Programs

Santee Cooper completed the rollout of an advanced meter infrastructure (or smart meters) to our retail customers in late 2021. Smart meters are more reliable, accurate and efficient than standard meters, and by sending customer energy usage directly to us, they eliminate the need for meter readers to physically read customer meters once a month. We also completed installation of a data management system that collects information from the smart meters. Next up is an interface to help customers access near-real-time energy usage. All together, these infrastructure upgrades will empower customers to make smart energy choices for themselves and their families or businesses.

Santee Cooper also launched a new suite of rebates to incentivize customers to take better control of their energy use. Called EmpowerSC, the program has already introduced rebates for electric vehicle chargers and incentives for a new demand response program, as well as renewed popular existing rebate programs for solar panels, HVAC units and more.

The year was an excellent one in terms of retail customer growth and satisfaction. Santee Cooper gained 4,764 retail customers in 2021, for a Dec. 31 total of 198,694 residential and commercial customers. In terms of customer satisfaction, our annual independent surveys found overall satisfaction among 95% of residential customers, 97% of commercial customers and 100% of industrial and municipal customers. Satisfaction reached an all-time low (7%) among electric cooperative leaders, and we recognize that this is a critical area we need to address in 2022 and beyond.

Environmental Stewardship

Santee Cooper earned the Smart Energy Provider (SEP) designation from the American Public Power Association for the second time in 2021. The designation recognizes a utility's commitment to energy efficiency, customer-based renewable generation, and environmental initiatives that help provide safe, reliable, low-cost, and sustainable electric service. Santee Cooper previously earned the two-year SEP designation in 2019, the first year APPA offered it.

In terms of wetlands restoration, Santee Cooper had two key projects underway in 2021: planting of native hardwood seedlings at our Camp Hall commerce park, and continuing restoration of 380 acres, including an industrial cooling pond and two excavated ash ponds, at the former Grainger Generating Station site in Conway. Crews planted 80,000 oak seedlings on 165 acres at Camp Hall in the winter, with plans to plant a total of more than 400 acres as part of our commitment to protect over 1,200 acres of wetlands at the park. At Grainger, Santee Cooper planted larger tree seedlings and cattails at the former ash ponds as part of our work to return those areas to wetlands.

In addition to our EV charger rebates, Santee Cooper has upgraded some outdated electric vehicle chargers across Horry County. Santee Cooper helped install the initial chargers 10 years ago and turned over ownership to the local governments and other owners who hosted the stations. In 2021, we supplied and installed new chargers at these local government and education locations across Horry County.

We observed two milestones in our renewable energy program in 2021: the 20th anniversary of Horry County Landfill Green Power Station, which introduced renewable power to South Carolina electric consumers in September 2001, and the 10th anniversary of dedicating the state's first utility-scale solar installation, the Grand Strand Solar Station.

Speaking of solar, in December the S.C. Department of Natural Resources named Santee Cooper's Jamison Solar Site the state's first Gold Certified Solar Habitat. Jamison is a 1.2-megawatt facility located on 5.4 acres in Orangeburg that is also home to a pollinator pathway. Santee Cooper has created other pollinator pathways along certain power line easements and in Camp Hall commerce park.

Economic Development

In March, the Board approved a new contract with Century Aluminum, providing all electric needs to its Mount Holly plant in Berkeley County from April 1, 2021 through Dec. 31, 2023.

Santee Cooper is serving Century under an experimental rate that takes advantage of incremental power. Because all of Century's load is served from Santee Cooper resources, the deal also freed up 150 megawatts of transmission capacity, used by Century under its earlier contract, which Santee Cooper now uses for economic wholesale market sales and purchases to benefit all customers.

The new power agreement allowed Century to expand operations at its Mount Holly plant and add approximately 100 jobs.

Camp Hall continued to grow with new sales and other development. Portman Industrial, Magnus Development Partners and RealtyLink announced site purchases, and construction continued of sports fields, a park, pathways and landscaping, all aimed at helping employees improve work-life balance. Volvo Car USA, Camp Hall's anchor tenant, opened a new training center at the park in 2021.

Beyond Camp Hall, Santee Cooper offers a range of economic development programs and incentives. In 2021, Santee Cooper worked with the state's electric cooperatives and other economic development partners to help attract more than 2,300 jobs and $1.4 billion in economic development investment across South Carolina.

Broadband Support

To help broadband providers more quickly build out retail service to unserved areas of South Carolina, Santee Cooper developed and launched a program in 2021 allowing retail broadband providers to access our excess fiber and transmission infrastructure.

Santee Cooper is not a provider of broadband, but instead will allow providers access to its 1,200 miles of excess fiber and transmission poles on the nearly statewide system to enable a faster and less expensive expansion into unserved areas. The need for enhanced broadband availability was highlighted in 2020, as the COVID-19 pandemic took hold and caused schools, medical facilities and others to switch to Internet-based access.

Conclusion

Reflecting upon the legislature's passage of Act 90, Santee Cooper welcomes this opportunity to do better. We have listened to concerns from lawmakers and our customers about the need for greater transparency and accountability, and we are working hard to meet these new requirements and expectations. Santee Cooper is the people's utility, and we are committed to a renewed focus on the people we serve as customers, and the people of the great state of South Carolina who own us.

Peter McCoy
Chairman

Charlie B. Duckworth
Acting President and CEO

Corporate Statistics

System Data 2021

Miles of transmission system lines[1]: **5,252**

Miles of distribution system lines: **3,069**

Number of transmission substations: **91**

Number of distribution substations: **59**

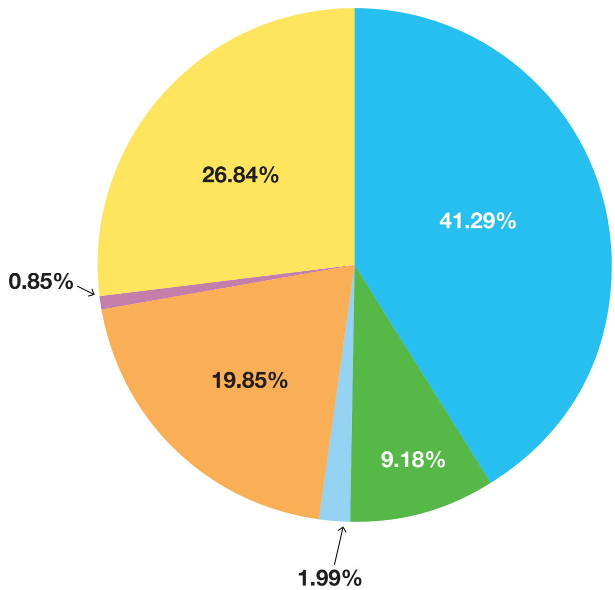
Number of CEPCI Delivery Points (DPs): **419**

[1] Includes Central-owned transmission lines

	2021	2020	2019	2018 As Restated	2017
FINANCIAL (Thousands)					
Total Revenues & Income	**$1,854,350**	**$1,689,760**	$1,613,518	$1,963,805	$1,732,327
Total Expenses & Interest Charges	**$1,801,232**	**$1,583,275**	$1,676,509	$1,766,507	$1,618,084
Other	**$3,146**	($54,431)	$48,681	($4,286)	($5,561)
Reinvested Earnings	**$56,264**	**$52,054**	($14,310)[2]	$193,012	$108,682
OTHER FINANCIAL					
(Excluding CP and Other)					
Debt Service Coverage *(prior to Distribution to State and Special Item)*	**1.27**	**1.46**	1.43	1.54	1.51
Debt / Equity Ratio	**76/24**	**76/24**	76/24	75/25	78/22
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**198,694**	**193,930**	189,177	185,116	180,658
Military and Large Industrial	**27**	**27**	27	27	26
Wholesale	**4**	**4**	4	4	4
Total Customers	**198,725**	**193,961**	189,208	185,147	180,688
Generation (GWh):					
Coal	**10,441**	**8,502**	9,126	11,130	9,589
Nuclear	**2,322**	**2,569**	2,746	2,447	2,296
Hydro	**504**	**782**	592	603	382
Natural Gas and Oil	**5,020**	**5,472**	5,582	5,101	5,783
Landfill Gas and Renewables	**214**	**63**	64	62	73
Total Generation (GWh)	**18,501**	**17,388**	18,110	19,343	18,123
Purchases, Net Interchanges, etc. (GWh)	**6,783**	**5,601**	5,891	4,838	4,980
Wheeling, Interdepartmental, and Losses	**(683)**	**(756)**	(772)	(463)	(324)
Total Energy Sales (GWh)	**24,601**	**22,233**	23,229	23,718	22,779
Summer Maximum Continuous Rating (MCR) Generating Capability (MW)	**5,115**	**5,115**	5,115	5,112	5,104
Territorial Peak Demand (MW)	**4,634**	**4,673**	4,558	5,203	4,989

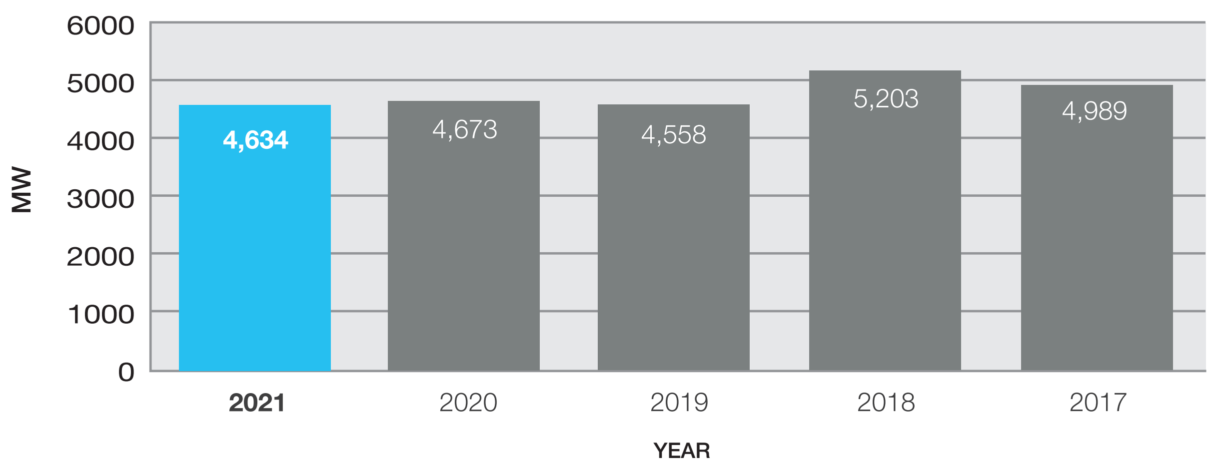
[2] 2019 financial results included a decrease to reinvested earnings from higher net amortization of the Regulatory assets - nuclear over the Deferred inflows - Toshiba settlement. This amortization was to align with impacts from the 2019 debt defeasance as well as capital expenditures.

2021 GENERATION BY FUEL MIX

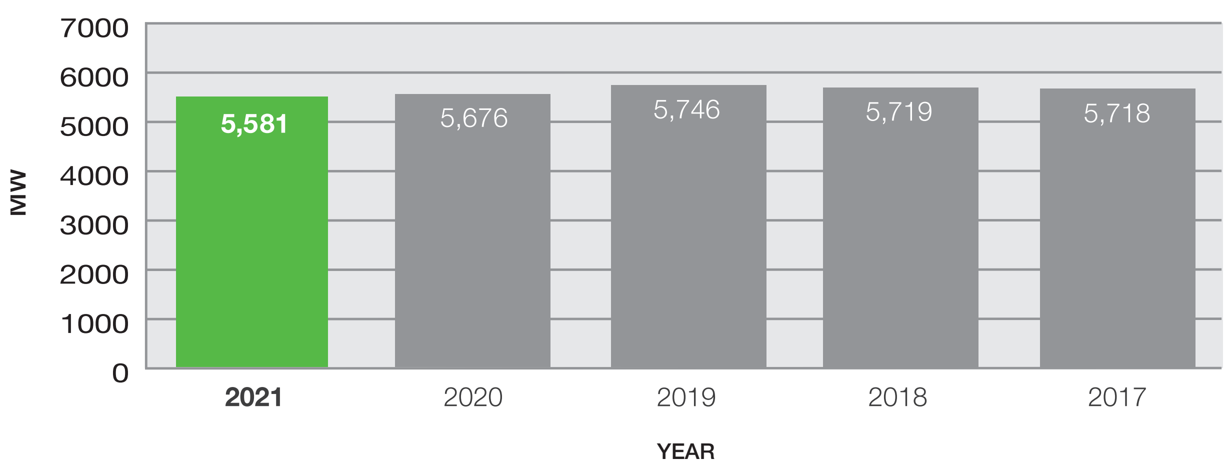


Source		GWh
Coal	41.29%	10,441
Nuclear	9.18%	2,322
Hydro	1.99%	504
Natural Gas	19.85%	5,020
Oil	0.0%	0
Total Renewables	0.85%	214
Purchases (Net)	26.84%	6,783
	100.00%	25,284

PEAK DEMAND



TOTAL CAPABILITY (MCR) WITH FIRM PURCHASES



Audit Committee Chairwoman's Letter

The Audit Committee of the Board of Directors is comprised of independent directors Peggy H. Pinnell – Chairwoman, William A. Finn, Merrell W. Floyd, Charles H. Leaird, Stephen H. Mudge and Barry D. Wynn.

The committee receives regular reports from members of management and Internal Audit regarding their activities and responsibilities.

The Audit Committee oversees Santee Cooper's financial reporting, internal controls and audit process on behalf of the Board of Directors.

Periodic financial statements and reports pertaining to operations and representations were received from management and the internal auditors. In fulfilling its responsibilities, the committee also reviewed the overall scope and specific plans for the respective audits by the internal auditors and the independent public accountants. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent public accountants and with the General Auditor to discuss the results of the audit, the evaluation of Santee Cooper's internal controls, and the overall quality of Santee Cooper's financial reporting.

Peggy H. Pinnell

Peggy H. Pinnell
Chairwoman
2021 Audit Committee

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Cherry Bekaert LLP
CPAs & Advisors

Report of Independent Auditor

To the Advisory Board and Board of Directors
South Carolina Public Service Authority
Moncks Corner, South Carolina

Report on the Audit of the Financial Statements

Opinions

We have audited the financial statements of the business-type activities and fiduciary activities of the South Carolina Public Service Authority (the "Authority") (a component unit of the state of South Carolina), as of and for the years ended December 31, 2021 and 2020, and the related notes to the financial statements, which collectively comprise the Authority's basic financial statements as listed in the table of contents.

In our opinion, the accompanying financial statements referred to above present fairly, in all material respects, the respective financial position of the business-type activities and fiduciary activities of the Authority, as of December 31, 2021 and 2020, and the respective changes in financial position, and, where applicable, cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinions

We conducted our audits in accordance with auditing standards generally accepted in the United States of America ("GAAS") and the standards applicable to financial audits contained in *Government Auditing Standards* (*Government Auditing Standards*), issued by the Comptroller General of the United States. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are required to be independent of the Authority and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Authority's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

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In performing an audit in accordance with GAAS and *Government Auditing Standards*, we

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Authority's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis and the required supplemental financial data as listed in the table of contents be presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audits of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the Chairman and CEO Letter, Corporate Statistics, Audit Committee Chairwoman's Letter, Leadership, and Office Locations but does not include the basic financial statements and our auditor's report thereon. Our opinions on the basic financial statements do not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the basic financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the basic financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated March 11, 2022 on our consideration of the Authority's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the Authority's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering Authority's internal control over financial reporting and compliance.

Cherry Bekaert LLP

Raleigh, North Carolina
March 11, 2022

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The South Carolina Public Service Authority (the "Authority" or "Santee Cooper") is a component unit of the State of South Carolina (the "State"), created by the State in 1934 for the purpose of providing and aiding interstate commerce, navigation, electric power and wholesale water to the people of South Carolina. The statute under which it was created provides that the Authority will establish rates and charges so as to produce revenues sufficient to provide for payment of all expenses, the conservation, maintenance and operation of its facilities and properties and the payment of the principal and interest on its notes, bonds, or other obligations; provided, however, that prior to putting into effect any increase in rates the Authority shall give at least a sixty-day notice of such increase to all customers who will be affected. Further rate related requirements were imposed by Act 90 and are described in the Legislative Matters section on page 23.

The Authority's assets include wholly-owned and ownership interests in a variety of coal, natural gas, nuclear, hydro, biomass, landfill and solar generating units totaling 5,115 megawatts (MW) of summer power supply peak capability. This consists of 3,500 MW of coal-fired capacity, 1,117 MW of natural gas and oil capacity, 322 MW of nuclear capacity, 142 MW of hydro capacity, 29 MW of landfill methane gas capacity and 5 MW of solar capacity. In addition to its generation assets, the Authority may purchase from, sell to or exchange with other bulk electric suppliers additional capacity and energy in order to maximize the efficient use of generating resources, reduce operating costs and increase operating revenues. The Authority also operates an integrated transmission system which includes lines owned by the Authority as well as those owned by Central Electric Power Cooperative Inc. ("Central"), the Authority's largest wholesale customer.

Overview of the Financial Statements

This discussion serves as an introduction to the basic and fiduciary financial statements of the Authority to provide the reader with an overview of the Authority's financial position and operations. As discussed in the Notes to the Financial Statements (Note 1 – A - "Reporting Entity"), the financial statements include the accounts of the Lake Moultrie and Lake Marion Regional Water Systems.

The Statements of Net Position – Business – Type Activities summarize information on the Authority's assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position.

The operating results of the Authority are presented in the Statements of Revenues, Expenses and Changes in Net Position – Business – Type Activities. Revenues represent billings for electricity and wholesale water sales. Expenses primarily include operating costs and debt service-related charges.

The Statements of Cash Flows – Business – Type Activities are presented using the direct method. This method provides broad categories of cash receipts and cash disbursements related to cash provided by or used in operations, non-capital related financing, capital related financing and investing activities.

The Statements of Fiduciary Net position – OPEB Trust Fund summarizes the assets, liabilities, and fiduciary net position of the OPEB Trust Fund.

The Statements of Changes in Fiduciary Net Position – OPEB Trust Fund reports additions to and deductions from the OPEB Trust Fund.

The Notes are an integral part of the Authority's basic financial statements and provide additional information on certain components of the financial statements.

Financial Condition Overview

The Authority's Statements of Net Position as of December 31, 2021, 2020 and 2019 are summarized below:

	2021	2020	2019
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	**$ 5,003,200**	$ 5,065,225	$ 5,120,393
Current assets	**1,400,548**	1,195,349	1,195,125
Other noncurrent assets	**4,436,986**	4,395,151	4,484,897
Deferred outflows of resources	**872,566**	895,719	968,477
Total assets & deferred outflows of resources	**$ 11,713,300**	$ 11,551,444	$ 11,768,892
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	**$ 6,961,591**	$ 6,857,277	$ 6,901,130
Current liabilities	**671,887**	614,928	690,985
Other noncurrent liabilities	**1,240,899**	1,379,405	1,474,063
Deferred inflows of resources	**700,143**	600,183	637,638
Total liabilities & deferred inflows of resources	**$ 9,574,520**	$ 9,451,793	$ 9,703,816
NET POSITION			
Net invested in capital assets	**$ 2,010,384**	$ 2,090,633	$ 2,041,105
Restricted for debt service	**9,214**	12,107	7,963
Restricted for capital projects	0	119	135
Unrestricted (deficit)	119,182	(3,208)	15,873
Total net position	**$ 2,138,780**	$ 2,099,651	$ 2,065,076
Total liabilities, deferred inflows of resources & net position	**$ 11,713,300**	**$ 11,551,444**	$ 11,768,892

2021 Compared to 2020

The primary changes in the Authority's financial condition as of December 31, 2021 and 2020 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources increased $161.9 million during 2021 due to increases of $205.2 million in current assets and $41.8 million in other noncurrent assets. These increases were offset by smaller decreases of $62.0 million in capital assets and $23.1 million in deferred outflows of resources.

The decrease in capital assets of $62.0 million was due to higher accumulated depreciation of $170.0 million, offset by net capital asset additions. The capital asset additions included utility plant for the Sandy Run-Orangeburg transmission line, distribution services projects, nuclear projects unitizations, ash handling conversion equipment installed to meet the Coal Combustion Residual Rule (CCR Rule) and Effluent Limitations Guidelines and Standards (ELG Rule) established by the United States Environmental Protection Agency (EPA).

The increase in current assets of $205.2 million was primarily due to increases in unrestricted and restricted cash and investments of $207.8 million. These consist of net increases from proceeds received from the 2021B improvement bonds less debt service payments, funding the current year cash defeasances and capital expenditures. Regulatory assets – nuclear also increased by $30.0 million due to transfers from noncurrent regulatory assets – nuclear, net of current year amortization. Also, prepaid expenses & other current assets increased by $23.6 million due mainly to an increase in the current derivative assets. Offsetting these increases were decreases in receivables of $34.4 million, primarily caused by differences between the years for the unbilled fuel receivable, Central Electric, and the long-term debt interest accrual receivable. Also fuel stocks decreased by $20.7 million due to coal supplier and transportation issues.

The increase in other noncurrent assets of $41.8 million was mainly due to increases of $65.1 million in noncurrent derivative gains and higher gains of $12.5 million from energy purchases from TEA. These increases were offset partially by a decrease in noncurrent regulatory assets – nuclear of $36.5 million due a transfer to current.

Deferred outflows of resources decreased $23.2 million due mainly to the Regulatory asset-asset retirement obligation (ARO) which decreased $18.8 million from continued ash pond removals. Unamortized loss on refunded and defeased debt also decreased $13.6 million from a combination of normal amortization on all issues and removals of a portion of balances of the 2021A refunding and 2021 commercial paper partial redemption. The accumulated fair value of hedging derivatives also decreased by $7.4 million due to higher deferred losses compared to the prior period. These decreases were partially offset from increases in the deferred outflow – pension of $9.8 million and the deferred outflow – OPEB of $6.8 million resulting from the 2021 actuarial studies and payments made after the measurement period.

LIABILITIES, DEFERRED INFLOWS OF RESOURCES & NET POSITION

Liabilities & deferred inflows of resources increased $122.7 million due to increases of $104.3 million in long-term debt, $57.0 million in current liabilities, and $100.0 million in deferred inflows of resources. These increases were partially offset by a decrease of $138.5 million in other noncurrent liabilities.

Long-term debt - net increased $104.3 million primarily due to the addition of the 2021AB Refunding & Improvement issue of $430.3 million and the associated debt premium of $97.4 million. This was offset by a decrease resulting from the payment of the portion of the principal balances from the 2021A and commercial paper refunding totaling $191.3 million, as well as a $91.0 million decrease in long-term revolving credit agreements due to the 2021B Improvement bond issue proceeds being used to pay the balances down. Separate from a $97.3 million increase in debt premiums associated with the 2021 AB bonds, unamortized debt discounts and premiums also decreased $32.5 million for amortization of discounts and premiums as well as refunding activity.

The increase in current liabilities of $57.0 million was due to increases in other current liabilities of $76.1 million. The other current liabilities increase was a result of higher regulatory liability offsets of $56.2 million due to hedging collateral received from higher natural gas prices and revenue adjustments of $18.7 million. Also adding to the increase was higher accounts payable of $50.5 million. The accounts payable increase was a result of purchased power liability of $37.5 million due to lower coal generation, fuel purchase liability increases of $18.9 million from higher natural gas prices and increased year-end accruals, and Summer nuclear accounts payable of $7.4 million. These accounts payable increases were offset by a lower coal liability of $20.1 million resulting from supply chain issues.

The decrease in other noncurrent liabilities of $138.5 million resulted mainly from a reduction of $77.2 million in other credits and noncurrent liabilities of $70.0 million for the Cook Settlement (see Note 10- *Legal Matters*) transfer to other current liabilities and $6.5 million in lower amortization of the regulatory liability associated with Summer nuclear 2 & 3 sales. Also contributing to this decrease was a lower net pension liability of $49.0 million, resulting from better-than-expected investment performance, and a lower asset retirement obligation of $24.8 million primarily due to ash pond removals. Somewhat offsetting this was higher unamortized debt discounts and premiums of $64.9 million due mainly to debt premium increases of $97.4 million related to the 2021AB Refunding and Improvement bond issue. Also offsetting this increase was $26.9 million in debt premium amortization and $6.6 million in debt premium removals resulting from the 2021A Refunding bond issue. Further offsets were provided by long-term debt (net of current portion) increases of $39.5 million due to long-term debt net increases of $130.5 million from the addition of $430.3 million related to the 2021AB Refunding and Improvement bond issue, a $174.4 million decrease for removals of balances resulting from the 2021A Refunding bond issue, a $16.9 million decrease for removals of the 2019A Refunding water system bond refunded by commercial paper and a $108.5 million decrease due to transfers to current portion. Also contributing was lower Long Term Revolving Credit Agreements of $91.0 million due to paydowns from the 2021 B Improvement bond issue proceeds.

Deferred inflows of resources increased $100.0 million largely due to higher accumulated increase in fair value of hedging derivatives of $103.3 million due to higher gains associated with higher natural gas prices increasing futures settle prices in 2021. Further increases were provided by deferred inflows – pension of $48.5 million associated with better investment performance in the 2021 actuarial study. Somewhat offsetting these increases were amortization of $45.3 million of the deferred inflows - Toshiba settlement to align with utilizing settlement funds to fund debt defeasances and funds used for capital expenditures. Further offsets were provided by deferred inflow - OPEB of $4.7 million from the 2021 actuarial study.

The increase in net position of $39.1 million was due to positive operating results. Unrestricted net position increased $122.3 million, offset by lower net investment in capital assets of $80.2 million. Further offsets were provided by lower restricted net position of $3.0 million.

2020 Compared to 2019

The primary changes in the Authority's financial condition as of December 31, 2020 and 2019 were as follows:

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

Total assets and deferred outflows of resources decreased $217.4 million during 2020 due to decreases of $55.2 million in capital assets, $89.7 million in other noncurrent assets and $72.8 million in deferred outflows of resources.

The decrease in capital assets of $55.2 million was due to from higher accumulated depreciation of $196.3 million offset by net capital asset additions. The capital asset additions included net utility plant additions of $55.3 million for a Pomaria-Sandy Run transmission line, distribution services projects and ash handling conversion equipment installed to meet the Coal Combustion Residual Rule (CCR Rule) and Effluent Limitations Guidelines and Standards (ELG Rule) established by the United States Environmental Protection Agency (EPA). Nuclear unitizations also added to the decrease in construction work in progress.

The decrease in other noncurrent assets of $89.7 million was primarily due to a decrease in costs to be recovered from future revenues (CTBR) of $54.4 million due to an adjustment to revised depreciation amortization in the CTBR depreciation calculation (See Note 2 – *Costs to be Recovered From Future Revenue (CTBR)*). Also contributing were decreases in other noncurrent and regulatory assets of $31.7 million, largely from decreases in billable projects driven by the unitization of energy efficiency rebate programs that are transferred to plant in-service, with an offset to billable projects and an advance payment being received on a solar billable project for which work has not started. The regulatory asset – nuclear decreased $13.6 million from $7.1 million in adjustments and $6.5 million being transferred to current.

Deferred outflows of resources decreased $72.8 million largely due to reductions in the accumulated decrease in fair value of hedging derivatives of $33.7 million resulting from higher futures settle price in 2020 reducing losses. Regulatory asset - asset retirement obligation (ARO) decreased $24.2 million from continued ash pond removals as well as a nuclear ARO update from a 2019 TLG decommissioning cost study. Unamortized loss on refunded and defeased debt decreased $24.3 million from $12.3 million in removals of a portion of balances resulting from the November 2020 refunding and the December 2020 cash defeasance. Also contributing were reductions of $14.2 million for normal monthly amortization of debt losses for all outstanding issues. Further decreases were provided by deferred outflow - OPEB of 46.1 million from a 2020 actuarial analysis. Somewhat offsetting these decreases were higher deferred outflows - pension of $15.6 million from a 2020 actuarial analysis.

LIABILITIES, DEFERRED INFLOWS OF RESOURCES & NET POSITION

Liabilities & deferred inflows of resources decreased $252.0 million due to decreases of $43.9 million in long-term debt, $76.1 million in current liabilities, $94.7 million in other noncurrent liabilities and $37.5 million in deferred inflows of resources.

Long-term debt net decreased $43.9 million primarily due to a cash bond defeasance of $57.2 million as well as net transfers to current portion of long-term debt of $15.3 million. Unamortized debt discounts and premiums decreased $15.6 million for amortization of discounts and premiums as well as defeasance and refunding activity. These decreases were offset by a net increase of $65.0 million on long-term revolving credit agreements due to current year draws. Also, the net impact of the 2020AB Refunding and 2020A improvement issue provided an increase of $68.6 million.

The decrease in current liabilities of $76.1 million was due to decreases in short-term revolving credit agreement of $64.2 million from higher net paydowns. Accounts payable decreased $20.9 million due mainly to decreases of $17.3 million in the Summer Nuclear accounts payable liability due to lower year-end accruals for V.C. Summer Units 2&3. Also, the liability for major fuel (oil and gas purchases) decreased by $3.2 million. Further contributing were other current liabilities of $32.7 million from lower revenue adjustments of $13.0 million, lower current derivative regulatory offsets of $8.7 million and a smaller accrued nuclear reloading expense of $5.1 million. The remaining net variance is spread across the remaining liability accounts in this category. These decreases were offset by increases of $28.9 million in commercial paper and $15.3 million in current portion of long-term debt.

The decrease in other noncurrent liabilities of $94.7 resulted mainly from a reduction of $73.9 million in other credits and noncurrent liabilities of $65.0 million for the Cook Settlement (see Note 10 – *Legal Matters*). Also contributing to this variance was a $13.9 million decrease in noncurrent derivative losses regulatory offsets. Somewhat offsetting this was an increase in unamortized gain on refinanced debt of $10.1 million from the 2020AB refunding. The net OPEB liability decreased $10.6 million from the 2020 actuarial analysis. Further decreases resulted from ARO changes of $23.6 million from continued ash pond removals as well as a nuclear ARO update from a 2019 TLG decommissioning cost study. Lower construction liabilities contributed $5.2 million to the variance. Somewhat offsetting these decreases were increases in the net pension liability of $18.6 million resulting from the 2020 actuarial study.

Deferred inflows of resources decreased $37.5 million largely due to amortization of $69.8 million of the Regulatory Inflows-Toshiba Settlement to align with utilizing settlement funds to fund debt defeasances and funds used for capital expenditures. Somewhat offsetting this decrease was an increase in nuclear decommissioning costs of $15.4 million due to current year funding and earnings growth. The accumulated increase to fair value of hedging derivatives also increased $12.3 million due to higher gains from current year futures settle prices in 2020. Further offsets were provided by increases in deferred inflows - OPEB and deferred inflows - pension of $2.6 million and $2.1 million, respectively resulting from the 2020 actuarial studies.

The increase in net position of $34.6 million was due to positive operating results. The increase in net position resulted in an increase in net investment in capital assets of $49.6 million, higher restricted net position for debt service of $4.1 million, and lower unrestricted net position of $19.1 million.

RESULTS OF OPERATIONS

Santee Cooper's Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2021, 2020 and 2019 are summarized as follows:

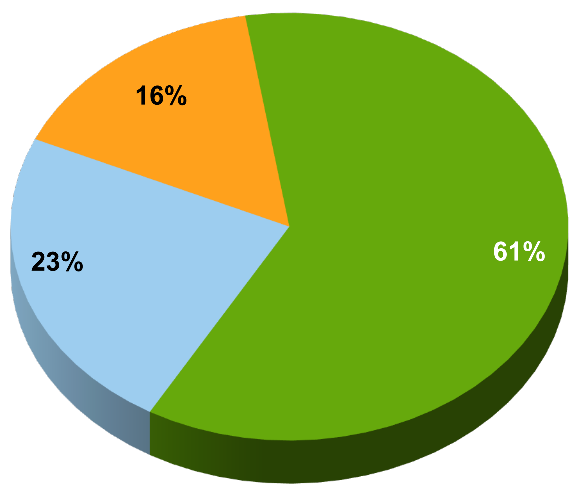
	2021	2020	2019
		(Thousands)	
Operating revenues	**$ 1,765,785**	$ 1,627,427	$ 1,722,676
Operating expenses	**1,496,286**	1,263,683	1,319,872
Operating income	**269,499**	363,744	402,804
Interest expense	**(304,946)**	(319,592)	(356,641)
Costs to be recovered from future revenue	**3,145**	(54,431)	48,681
Other income	**88,566**	62,333	(109,154)
Transfers and special item	**(17,135)**	(17,479)	(217,496)
Change in net position	**$ 39,129**	$ 34,575	$ (231,806)
Net position - beginning of period	**$ 2,099,651**	$ 2,065,076	$ 2,296,882
Ending net position	**$ 2,138,780**	$ 2,099,651	$ 2,065,076

2021 Compared to 2020

Operating Revenues

Compared to 2020, operating revenues increased $138.4 million (9%), primarily due to higher energy sales (11%) and demand usage (13%), largely due to impacts from the Covid-19 pandemic in the prior year. Also contributing to energy sales were the new agreement with Century Aluminum and increased production requirements at Nucor, adding $42.5 million and $19.7 million in 2021, respectively. Milder weather during 2020 also added to the increase in 2021. Additionally, higher demand and fuel rate revenues of $6.5 million and $34.5 million, respectively, added to the increase. There was also an increase from Century's supplemental energy requirements of $29.1 million. Somewhat offsetting these increases were decreases to revenue from the Central Cost of Service true-up adjustments totaling $28.2 million. Also contributing to the decrease were impacts from prior year Central Economic Development Rider (EDR) revenues of $13.7 million not present in the current year due to their participation in the program ending. Energy sales for 2021 totaled approximately 24.6 million megawatt hours (MWhs), as compared to approximately 22.2 million MWhs for 2020.

2021 Revenues from Sales of Electricity*
by Customer Class

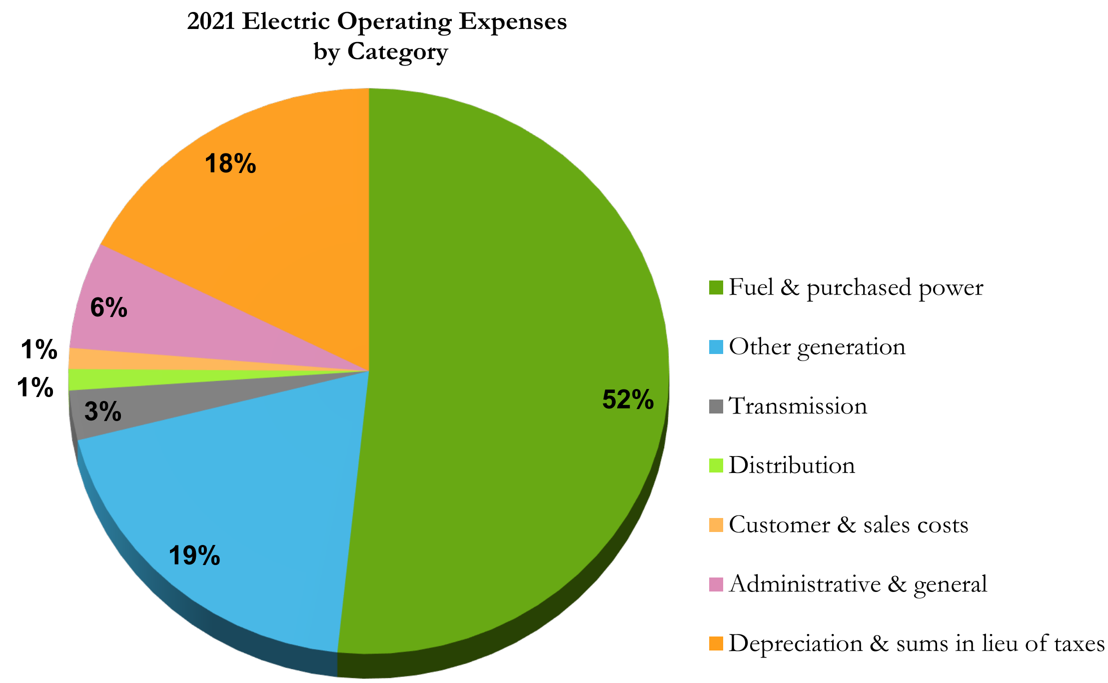


		2021		2020		2019
Revenues from Sales of Electricity*				(Thousands)		
Retail	**$**	**406,969**	$	383,267	$	407,419
Industrial		**274,202**		196,683		224,967
Sales for resale		**1,059,588**		1,022,398		1,062,056
Totals	**$**	**1,740,759**	$	1,602,348	$	1,694,442

*Excludes interdepartmental sales of $582 for 2021, $577 for 2020 and $613 for 2019.

OPERATING EXPENSES

Operating expenses for 2021 increased $232.6 million (18%) as compared to 2020. Primary drivers were higher fuel and purchased power expense of $172.5 million from higher kWh sales and increased use of purchased power due to plant outages and coal stockpile management as well as higher costs in the energy markets due to higher natural gas prices. Also contributing was the recent implementation of a non-cash coal adder to incentivize a lower coal burn to help maintain coal stockpile inventories for the upcoming winter. Somewhat offsetting this was lower natural gas generation during 2021 due to increased commodity prices. Non-fuel operating expenses increased $61.2 million largely from contract services and materials associated with plant outages at Cross, Rainey and Winyah as well as a Cross spring outage in the prior year being postponed until 2021. Also contributing was a COVID-19 reimbursement reversal; and depreciation ($14.1 million) mainly from assets placed into service in the current year. Somewhat offsetting these increases were lower administrative and general expenses of $14.8 million primarily due to a large actuarily determined GASB 68 (pension) credit from better-than-expected investment performance on trust assets.



		2021		2020		2019
Electric Operating Expenses				(Thousands)		
Fuel & purchased power	**$**	**770,115**	$	597,636	$	669,502
Other generation		**288,840**		227,679		264,844
Transmission		**42,338**		38,904		36,217
Distribution		**17,997**		17,413		17,925
Customer & sales costs		**17,903**		22,051		21,873
Administrative & general		**90,844**		105,608		102,914
Depreciation & sums in lieu of taxes		**262,134**		248,245		200,599
Totals	**$**	**1,490,171**	$	1,257,536	$	1,313,874

Net Below the Line Items

- Other income increased $26.2 million, resulting primarily from higher gains from TEA ($16.9 million) and lower current year net amortization expense ($17.1 million) associated with the Pee Dee and Nuclear Regulatory Asset and the Toshiba Regulatory Liability. This amortization is to align with impacts from debt defeasances as well as capital expenditures, which were greater in the prior year.

- Interest and amortization expense for 2021 was $14.1 million lower, primarily due to the 2020 AB refunding and the December 2020 defeasance.

- CTBR expense was lower by $57.4 million, mainly as result of the prior year adjustment to revise depreciation amortization to be recovered.

- Transfers represent dollars paid to the State.

2020 Compared to 2019

Operating Revenues

As compared to 2019, operating revenues decreased $95.2 million (6%), primarily due to lower fuel rate revenues ($51.6 million). Lower energy sales (4%) and demand usage (5%) reduced revenue by $35.8 million and $23.1 million, respectively. Milder weather throughout 2020 contributed to the revenue decrease. The year-to-date weather adjusted impact attributed 45% of the decrease to weather, whereas the remainder was largely due to impacts from the COVID-19 pandemic. Somewhat offsetting this decrease was higher demand rate revenues of $19.5 million, primarily from Central. Also contributing to the decrease were impacts from a rate freeze that was implemented July 31, 2020. Energy sales for 2020 totaled approximately 22.2, as compared to approximately 23.2 for 2019.

Operating Expenses

Operating expenses for 2020 decreased $56.2 million (4%) as compared to 2019. The main drivers were lower fuel and purchased power expense which decreased $71.9 million. This was due to lower kWh sales, lower commodity prices than prior year and a lower cost fuel mix. Other generation costs decreased $37.2 million from contract services and materials due to lower coal generation, as well as the majority of a Cross spring outage being shifted from 2020 to the spring of 2021. Nuclear expenses also were down from an outage true-up credit ($3.2 million) received in August as well as Dominion's voluntary retirement program and merger integration costs driving costs higher in the prior year. Also contributing was a year-end FEMA accrual ($4.3 million) for COVID-19 expense reimbursement. Somewhat offsetting this was higher: (i) depreciation ($51.8) due to new rates being implemented in 2020 as well as assets being placed into service in the current year; and (ii) transmission ($2.4 million) mainly from a FEMA accrual reversal.

Net Below the Line Items

- Other income increased $171.5 million, resulting largely from higher net amortization of the Nuclear Regulatory Asset ($353.3 million) and the Toshiba Regulatory Liability ($192.4 million) in the prior year. These amortizations are to align with impacts from debt defeasances as well as capital expenditures, which were greater in the prior year.

- Interest and amortization expense for 2020 was $37.0 million lower primarily from the 2019 debt defeasance and refunding.

- CTBR expense was higher by $103.1 million mainly as result of an adjustment to revise depreciation amortization to be recovered.

- Capital contributions, transfers and special items represent dollars paid to the State as well as a prior year special item. The payment to the State, which is based on a percentage of total budgeted revenues was in-line with the prior year. A special item was recorded in 2019 for the Cook case legal settlement of $200.0 million (see Note 10 – *Legal Matters*).

ECONOMIC CONDITIONS

The Authority and the electric industry continue to face economic and industry challenges that impact the competitiveness and financial condition of the utility. As market conditions fluctuate, the Authority's mission continues to be to deliver low-cost and reliable electricity and water to its customers.

To address these challenges, the Authority has developed business growth initiatives that revolve around four strategic initiatives - marketing, product development, project management and competitive rates. The Authority is marketing industrial and commercial properties that are served directly by the Authority and The Electric Cooperative partners and municipal customers. Product development activities include the creation and/or improvement of industrial properties, the acquisition of property, expansion of infrastructure into industrial properties, and/or constructing buildings for industrial use. Since June 2012, the Authority has invested over $105.0 million throughout South Carolina in product development activities through low interest revolving loans to public entities. The Authority continues to monitor the impacts of the Covid-19 pandemic on the business and serving existing customers. (See Note 14- *Impact of Novel Coronavirus (COVID-19) Pandemic*)

The Authority's commitment to economic development efforts with the State, The Electric Cooperatives and other economic development partners also brought additional announcements of business growth projects during 2021, including Scentsy in the City of Rock Hill, Central States Manufacturing in Aiken County, and Solstice Sleep Products in Marion County, among many others.

The Authority's largest customer, Central, accounted for 57.7 percent of sales revenues in 2021. Central provides wholesale electric service to each of the 20 distribution cooperatives which are members of Central pursuant to long-term all requirements power supply agreements. In September 2009, Central and the Authority entered into an agreement ("September 2009 Agreement") that, among other things, allowed Central to transition the portion of power and energy requirements of the five former Saluda members, (the "Upstate Load"), directly connected to the transmission system of Duke Energy Carolinas, LLC to another supplier. In January 2013, Central began transitioning the Upstate Load to Duke Energy Carolinas, a subsidiary of Duke Energy Corporation, ("Duke"). The load transition was complete on January 1, 2019 and amounted to approximately 900 MW. Nothing precludes the Authority from serving this load when the Duke agreement ends on December 31, 2030.

In May 2013, the Authority and Central agreed to extend their termination rights as noted in the September 2009 Agreement until December 31, 2058 ("Coordination Agreement"). Under the Coordination Agreement 10-year rolling notice provision, for a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. Central has entered into requirement agreements with all 20 of its member cooperatives that extends through December 31, 2058 and obligates those members to pay their share of Central's costs, including costs paid under the Coordination Agreement. The Authority and Central have resolved certain matters relating to the nuclear project through the execution of the Cook Settlement and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement.

Due to low gas prices, an uncertain regulatory environment, labor shortages, and an overall reduction in demand during the COVID-19 pandemic, many coal suppliers have taken their production capacity offline or reduced their production. With the reduction in supply and demand, transportation providers also furloughed employees and stored assets. Demand rebounded faster and stronger than expected over the course of 2021 and gas prices rose to levels that would typically trigger gas to coal fuel switching. However, coal supply is now limited as producers have adjusted their production in response to lower demand for coal over the years and ramping up production takes time. Coal supply has been limited even further recently due to the Authority's largest source of coal being shut down due to safety concerns at the mine. Additionally, the COVID-19 pandemic and labor shortages have made increasing production volumes and transportation of the coal difficult. Due to these coal supply issues, the Authority is experiencing coal inventory levels that are below its targeted operating levels.

The Authority's targeted range for coal on hand is 800 thousand to 1.2 million tons. As of December 31, 2021, the Authority had approximately 562 thousand tons of coal on hand which equates to approximately 34 days of inventory based on average daily burns projected for 2022. Colder than normal weather resulted in inventory levels further decreasing by approximately 100 thousand tons through the middle of February 2022. The continuation of this cold weather or continued supply chain disruptions would further reduce inventory levels and would extend the presently expected timeline for reaching the targeted range for coal on hand. The Authority currently expects production to resume at their largest coal source in the first quarter of 2022 with expected full capacity reached by the third quarter of 2022, along with gradual improvements to deliveries throughout the first half of 2022 and projects reaching the lower end of the targeted range in the second quarter of 2022.

The Authority reacted to the initial signs of these coal supply issues in the first quarter of 2021 by immediately implementing measures to conserve coal inventory for peak months. These measures included fuel switching away from coal consumption to natural gas and market purchases although it was uneconomical to do so due to elevated natural gas and power market prices. The Authority is continuing to run natural gas units and purchase power from the market to displace coal consumption in order to maintain adequate coal supply for the winter peak months. Recent lower than projected inventory levels thus far in 2022 could result in more extreme measures being taken to preserve coal supply inventory, potentially leading the Authority to utilize higher levels of the less economical natural gas units and purchase power, leading to materially increased costs.

The Authority had hedged most of its projected natural gas needs and a minimal amount of projected market purchases to help manage its fuel position during the rate freeze period. However, the coal supply issues, and associated measures taken by the Authority to reduce coal consumption, have resulted in natural gas consumption and market purchases above projected levels for the Authority. Average natural gas prices increased by more than 50% in 2021 compared to 2020 due to rising post-pandemic and weather-related demand and declines in production. Therefore, the Authority is experiencing operating expenses that are higher than budgeted due to being subject to inflated natural gas and purchase power pricing on all unhedged volumes. In addition, the Authority is currently charging most customers based on the Settlement Rates defined in the Cook Settlement Agreement, which does not include an adjustment mechanism based on the Authority's actual cost of fuel. The extent of these cost increases has yet to be determined; however, the Authority continues to monitor weather conditions and evaluate options to mitigate the impact on stockpiles, costs and revenues in 2022.

Legislative Matters

On June 8, 2021, the General Assembly passed, and on June 15, 2021, the Governor signed into law Act 90 of 2021 (H.3194), which establishes reforms by amending the state laws applicable to the Authority. Act 90 of 2021, among other things, includes the following provisions:

- Act 135 Extension. Extended the expiration date (from May 31, 2021 to December 31, 2021) of Act 135, which established certain operational guidelines for the Authority. Although Act 135 was extended, Act 90 of 2021 removed the requirement in Act 135 that the ORS conduct monthly reviews of the Authority and further authorized the Authority to proceed with the plan for the closing of the Winyah Generating Station and to enter into financial transactions for, among other purposes, converting variable rate debt to fixed rate debt and obtaining lower interest rates on existing debts, provided that overall debt load may not be increased by any such transaction.

- Joint Bond Review Committee Approval ("JBRC") Requirements for Bonds and Real Estate Transfers. Requires the JBRC to approve, reject, or modify a proposed issuance by the Authority of its (1) bonds, (2) notes, or (3) other indebtedness, including any refinancing that does not achieve a savings in total debt service. The JBRC has determined that any refinancing transactions that are not typically utilized by the State will require its approval. Act 90 of 2021 provides that JBRC approval is not required for the issuance of short-term or revolving-credit debt for the management of the Authority's day-to-day operations and financing needs. If the JBRC does not approve, reject, or modify a request for approval of a proposed debt issuance within sixty days, the issuance is deemed approved. A proposed debt issuance that receives JBRC approval may be issued across multiple series and over a three-year period of time.

  With the exception of encroachment agreements, rights of way, or lease agreements made by the Authority for property within the Federal Energy Regulatory Project boundary, a transfer of any interest in real property by the Authority, regardless of the value of the transaction, requires approval, rejection, or modification by the JBRC and the Authority is required, by September first of each year, to provide an annual report to the JBRC regarding every transaction involving an interest in real property executed during the preceding twelve months.

- Changes to Retail Rates Process. Establishes a retail rate process ("Retail Rate Process") for the Authority requiring the Authority to (i) adopt and publish pricing principles that balance certain factors including, but not limited to, adherence to the Authority's mission to be a low-cost provider, reliability, transparency, preservation of financial integrity, equity among customer classes, gradualism in adjustments to its pricing and rate schedule type, adequate notice to customers, relief mechanisms for financially distressed customers, and review of compliance with bond covenants, and (ii) submit to the ORS for its review and comment any proposed rate adjustments presented to the Board for the Board's approval.

  Act 90 of 2021 also establishes procedures for challenges to rates and authorizes the Authority to place adjusted rates and charges into effect on an interim basis not exceeding 18 months if needed to avoid a default of its obligations and to ensure proper maintenance of its System. The South Carolina Supreme Courts may not substitute its judgment for the judgment of the Board as to questions of fact when reviewing rate adjustments approved by the Board pursuant to Act 90 of 2021 which have been authorized by law and the remedy for a successful rate challenge is a prospective adjustment of a new rate.

- Construction, Acquisition and Purchase Requirements. Imposes certain limitations and approval requirements on the Authority with respect to the construction, acquisition, and purchase of major utility facilities, including that the Authority may not enter into a contract for the acquisition of a major utility facility without the prior approval of the South Carolina Public Service Commission ("SCPSC"). In addition, the Authority is required to file for SCPSC approval of a program for the competitive procurement of energy, capacity, and environmental attributes from renewable energy facilities to meet needs for new generation resources identified by the Authority in its integrated resource plans or other planning processes. The Authority also may not enter into a contract for the purchase of power with a duration longer than ten years without approval of the SCPSC unless the transaction is either (i) subject to the exclusive jurisdiction of FERC or another federal agency or (ii) a purchase of renewable power through a SCPSC approved competitive procurement.

- Board of Directors Qualifications. Revises the terms and qualifications for membership on the Board, provides for two non-voting ex-officio members, establishes their duties and responsibilities, and provides that violations of such duties and responsibilities constitutes grounds for removal by the Governor. Act 90 of 2021 provides a transition to a new board over a four-year period, changes board terms from seven years to four years and creates a three-term limit. Act 90 of 2021 establishes new experience and educational requirements for board members and directs the appointing authority, the Governor, to consider diversity when making appointments. Two non-voting ex officio members, appointed by the Authority's largest customer Central, are added to the Board.

  Each Board member is required to discharge his duties, in good faith, with the care an ordinarily prudent person in a like position would exercise under similar circumstances and in a manner he or she reasonably believes to be in the best interests of the Authority, which involves a balancing of, among other things, preservation of the financial integrity of the Authority and its operations, the interest of the Authority's residential, commercial and industrial retail customers in reliable, adequate, efficient, and safe service, at just and reasonable rates, regardless of customer class and the exercise of the powers of the Authority set forth in the Act in accordance with good business practices and the requirements of applicable licenses, laws, and regulations.

- Certain Compensation, Benefit and Severance Packages Subject to Review and Approval. Any compensation package, severance package, payment or other benefit conferred upon the Authority CEO or member of the Board of the Authority must first be reviewed and approved by the Agency Head Salary Commission of the State Fiscal Accountability Authority. Additionally, any employment contracts or retention contracts that last longer than five years, and all contract extensions, must be reviewed by the Agency Head Salary Commission. Any payment made or benefit given in violation of Act 90 of 2021 is subject to a claw-back of the payment or benefit in a legal action brought by the State Attorney General.

- Service Territory. Provides the process by which the Authority may enter into agreements with other electric suppliers on the reassignment of service areas.

- Authority and Jurisdiction of ORS, JBRC and SCPSC. Establishes the authority and jurisdiction of the ORS with respect to the Authority and sets forth certain on-going reporting and compliance requirements for the Authority, including filing of an integrated resource plan with the SCPSC, filing an annual report on transactions involving real property to the JBRC, and submission of books, records and other information requested by the ORS.

Act 90 of 2021 expressly states that the Retail Rate Process established by such Act does not limit or derogate from the State's covenants in Sections 58-31-30 and 58-31-360 of the Code of Laws of South Carolina 1976, as amended, not to impair, alter, limit or restrict the Authority's power to establish rates and charges sufficient to provide for payment of its expenses and debt service on its obligations, and those covenants are reaffirmed.

During the second half of 2021 and related to Act 90 of 2021, the Joint Bond Review Committee considered and approved several finance and real estate transactions of the Authority, the Agency Head Salary Commission approved a six-month contract extension and annual performance measures for Authority CEO Mark Bonsall, and the South Carolina Public Service Commission held an *ex parte* hearing related to its new regulatory authority over the Authority.

The Electric Market Reform Measures study committee established by Act 187 of 2020 met twice in 2021. This electric market study committee is made up of 8 legislators, 4 from the SC Senate and 4 from the SC House. The study committee is charged with analyzing whether South Carolina should consider any changes to its electric market structure. It is expected that this study committee will issue an interim report in 2022.

The South Carolina General Assembly adjourned its legislative session in December 2021. The General Assembly will finish its two-year legislative session in 2022.

Capital Improvement Program

The purpose of the capital improvement program is to continue to meet the energy and water needs of the Authority's customers with economical and reliable service. The Authority's three-year budget for the capital improvement program approved in 2021, 2020 and 2019 was as follows:

Approved in:		**2021**		2020		2019
		Budget 2022-24		Budget 2021-23		Budget 2020-22
Capital Improvement Expenditures				(Thousands)		
Environmental compliance [1]	**$**	**241,824**	$	167,622	$	147,633
New Load & Resource Plan [2]		**0**		0		72,018
General improvements and Other [3]		**723,266**		701,263		623,752
Totals	**$**	**965,090**	$	868,885	$	843,403

1 Environmental Compliance is composed of project costs associated with ash pond closures and solid waste landfill.
2 Reflects future generation and transmission cost associated with the current load and resource plan.
3 Budget 2021-2023 reflects acceleration of Advanced Metering Infrastructure and FERC relicensing costs. Other includes Camp Hall and Renewables.

As determined by the Authority, the capital improvement program will be funded from revenues, additional revenue obligations, commercial paper, internal funding sources and other short-term obligations.

Summer Nuclear Units 2 and 3

Events Relative to Summer Nuclear Units 2 and 3

In January of 2008, the Authority approved a generation resource plan that included the development of two new 1,117 MW nuclear generating units (individually, "Summer Nuclear Unit 2" and "Summer Nuclear Unit 3" and together, "Summer Nuclear Units 2 and 3") at the V.C. Summer Nuclear Generating Station. Summer Nuclear Units 2 and 3 would be jointly-owned by the Authority (45% ownership interest) and, at the time, SCE&G (now known as Dominion) (55% ownership interest) (together, the "Owners").

In May of 2008, SCE&G, acting for itself and as agent for the Authority, entered into the EPC Agreement, with a contractor consortium consisting of Westinghouse and Stone & Webster, Inc. ("Stone & Webster" and together with Westinghouse, the "Consortium"), a wholly-owned subsidiary of Shaw. Under the EPC Agreement, the Consortium would supply, construct, test and start up Summer Nuclear Units 2 and 3, with guaranteed substantial completion dates of April 2016 for Summer Nuclear Unit 2 and January 2019 for Summer Nuclear Unit 3. In addition, Westinghouse's indirect parent company, Toshiba Corporation ("Toshiba"), provided a guaranty of Westinghouse's payment obligations under the EPC Agreement (the "Guaranty") and Stone & Webster's parent company, Shaw, likewise provided a guaranty of Stone & Webster's payment obligations under the EPC Agreement.

The cost of Summer Nuclear Units 2 and 3 was originally estimated to be approximately $9.8 billion. Based on its 45% ownership interest, the Authority's portion of the cost to construct Summer Nuclear Units 2 and 3 was approximately $4.4 billion. The Authority's funding sources for Summer Nuclear Units 2 and 3 consisted of the proceeds of Revenue Obligations issued pursuant to the Revenue Obligation Resolution between 2008 and 2016 and outstanding in the aggregate principal amount of $3.630 and $3.634 million as of December 31, 2021 and 2020, respectively.

During the course of construction, issues materialized that affected the budget and schedule for Summer Nuclear Units 2 and 3. In February of 2017, Toshiba Corporation announced a $6.3 billion write-down on the value of Westinghouse, stemming from its two U.S. nuclear construction projects, Summer Nuclear Units 2 and 3 and Units 3 and 4 at the Vogtle nuclear power plant located in Burke County, Georgia ("Vogtle Nuclear Units 3 and 4"). A month later, Westinghouse and 29 affiliated companies filed a petition pursuant to Chapter 11 of the Bankruptcy Code (the "Petition") in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court").

After the filing of the Petition, the Owners, led by SCE&G, conducted a comprehensive analysis regarding the continued viability of Summer Nuclear Units 2 and 3. The analysis revealed that: (i) the costs to complete Summer Nuclear Units 2 and 3 (including labor costs) would be much higher than previously expected; and (ii) the construction schedule would take much longer than previously expected. In particular, (i) the Owners' analysis estimated that completion of Summer Nuclear Units 2 and 3 would be delayed until 2023 for Summer Nuclear Unit 2 and 2024 for Summer Nuclear Unit 3 and (ii) the new cost estimate for Summer Nuclear Units 2 and 3 was over $25 billion, placing the Authority's 45% share at $11.4 billion ($8 billion in construction costs and $3.4 billion in interest expense), an increase from the then-current projected cost of $6.2 billion.

The Owners also entered into negotiations with Toshiba for the purpose of acknowledging and defining Toshiba's obligations under the Guaranty and establishing a schedule for the full payment of such obligations to the Owners. As a result, in July of 2017, the Owners and Toshiba entered into a settlement agreement (the "Toshiba Settlement Agreement") which included, among other things Toshiba's agreement that it would pay the Guaranty obligation in the amount of $2.168 billion (the Authority's share (based on its 45% ownership interest) equaling $975.6 million)), in accordance with a payment schedule commencing in 2017 and continuing through 2022.

On July 31, 2017, the Authority approved the wind-down and suspension of construction of Summer Nuclear Units 2 and 3 and the preservation and protection of the site and related components and equipment. SCANA approved similar action on the same day. To date, the Authority had spent approximately $4.7 billion in construction and interest costs. Upon suspending construction, and in accordance with GASB 62, the Authority ceased capitalizing interest expense on the debt incurred to fund Summer Nuclear Units 2 and 3 as of July 31, 2017.

In early September of 2017, the Owners filed two proofs of claim in unliquidated amounts in connection with the Westinghouse bankruptcy proceeding. Later that month, the Owners and Citibank, N.A. ("Citibank") entered into an Assignment and Purchase Agreement (the "Assignment and Purchase Agreement"), pursuant to which the Owners sold and assigned rights to receive payment under the Toshiba Settlement Agreement and rights, duties and obligations arising under the two proofs of claim filed in the Westinghouse bankruptcy proceeding to Citibank, in exchange for a purchase price of $1,847,075,400 (the Authority's share (based on its 45% ownership interest) equaling $831,183,930). Excluded from the sale was the initial $150 million payment (the Authority's share (based on its 45% ownership interest) equaling $67.5 million) received by the Owners under the Toshiba Settlement Agreement.

In January of 2018, the Owners entered into Amendment No. 1 of the Toshiba Settlement Agreement and Amendment No. 1 of the Assignment and Purchase Agreement. These amendments had the effect of capping at $60 million the Owners' current obligation to reimburse Citibank for payments the Owners received from the Westinghouse estate that had the effect of reducing mechanics liens at the site of Summer Nuclear Units 2 and 3 (the Authority's share (based on its 45% ownership interest) equaling $27.0 million). To date, the Owners have not made any reimbursement payments to Citibank.

Also, in January, the State's Department of Revenue ("DOR") notified SCE&G that the sales and use tax returns for Summer Nuclear Units 2 and 3 had been assigned for a sales and use tax audit. During a meeting in February, the DOR took the position that, because Summer Nuclear Units 2 and 3 had been abandoned and the facility was not completed and would not produce electricity, the materials for Summer Nuclear Units 2 and 3 were not tax-exempt and sales tax payments were due on previously tax-exempt purchases. In May, the DOR issued a proposed notice of assessment in the amount of $421 million. The Authority has submitted a protest to the notice of proposed assessment and continues to dispute the position that sales taxes are due and owing. Pursuant to an agreement between the Authority and Dominion ancillary to the Cook Settlement, Dominion agreed to hold the Authority harmless for any potential liability associated with the Department of Revenue Matter.

In March of 2018, the Bankruptcy Court issued its order confirming Westinghouse's Chapter 11 plan of reorganization (the "Westinghouse Plan of Reorganization"). The Westinghouse Plan of Reorganization provided for the sale of Westinghouse to Brookfield Business Partners, L.P. ("Brookfield") for $4.6 billion, which occurred in August of 2018.

The Westinghouse Plan of Reorganization also provided for the payment of claims made by allowed general unsecured creditors in an amount equal to the lesser of: (i) their pro rata share of certain funds; or (ii) 100% of the amount of the allowed claim. Under the Westinghouse Plan of Reorganization, creditors providing materials and services at the site of Summer Nuclear Units 2 and 3 were classified as Class 3A General Unsecured Creditors. In December of 2018, an initial distribution was made on behalf of the Westinghouse estate to Class 3A General Unsecured Creditors equaling approximately 25% of the allowed amount of each claim. Subsequently, a catch-up payment was made representing 75% of the allowed amount of each claim. Representatives of W. Wind Down Company, LLC, the entity responsible for paying the Westinghouse claims under the supervision of the Bankruptcy Court, has represented to the Owners that funds have been reserved to pay 100% of the presently disputed claims by the Class 3A General Unsecured Creditors. In the event that such disputed claims are not paid in full from the Westinghouse estate, the Class 3A General Unsecured Creditors could claim that the Authority is liable for payment under a mechanic's lien theory.

In June of 2018, SCE&G and the Authority signed a Right of Entry Agreement allowing the Authority to begin implementation of a Maintenance, Preservation, and Documentation (MPD) Program to preserve the equipment relative to Summer Nuclear Units 2 and 3 for sale. The Authority contracted with Fluor to perform an assessment of the condition of the equipment and to implement an MPD Program to help protect its value. Fluor began this scope of work in July of that year. The Authority has since approved an extension of the MPD Program through the first quarter of 2022. The Authority has spent $15.8 million through December 2021 to preserve the equipment.

In January of 2019, SCANA and its subsidiaries, including SCE&G, merged with Dominion. Through the merger, SCANA became a wholly-owned subsidiary of Dominion.

On April 5, 2019, Westinghouse filed an adversary proceeding complaint in the United States Bankruptcy Court for the Southern District of New York against the Authority, claiming that it is the owner of and has title to certain equipment related to the construction of Summer Nuclear Units 2 and 3 pursuant to the EPC Agreement. The parties settled the matter on August 29, 2020.

Sale of Summer Nuclear Units 2 and 3 Assets

After suspending construction, the Authority sought additional project partners or financial support for Summer Nuclear Units 2 and 3. Finding none, the Authority looked to whether or not it could sell the fuel assets and non-fuel assets comprising Summer Nuclear Units 2 and 3 equipment and commodities. First, an evaluation was conducted in accordance with GASB 42 to determine whether the assets were impaired. With the exception of certain assets to be repurposed at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the assets were determined to be impaired because: (i) the decline in service utility of the assets was large in magnitude; (ii) the event or change in circumstance was outside the normal life cycle of the assets; and (iii) although Summer Nuclear Units 2 and 3 could be completed at some point in the future, the Authority had no near-term plans to do so. Next, the Authority set out to determine the fair value of the impaired assets.

Based on the results of a fair value determination of the assets, the write-off of the construction costs and fuel for Summer Nuclear Units 2 and 3 for the year ended December 31, 2017 totaled $4.211 billion. In January of 2018, the Authority approved the use of regulatory accounting for the $4.211 billion impairment write-off. The majority of Summer Nuclear Units 2 and 3 was financed with borrowed funds and for rate-making purposes, the Authority includes the debt service on these borrowed funds in its rates. Therefore, the impairment will be recorded as a regulatory asset and amortized through November 2056 to align with the principal payments on the associated indebtedness.

In December of 2017, the Authority approved the use of regulatory accounting to defer a portion of post-suspension capitalized interest. With the cessation of capitalized interest and the timing of the suspension, the Authority would be unable to collect a portion of the post-suspension capitalized interest in its rates. Such post-suspension capitalized interest totaled $37.1 million as of December 31, 2017 and, like the $4.211 billion impairment write-off, is recorded as a regulatory asset and amortized through November 2056 in order to align with the principal payments on the debt used to pay the interest.

In December of 2017, the Authority also approved the use of regulatory accounting to defer the recognition of income from the Toshiba Settlement Agreement. The Authority recorded a regulatory deferred inflow of $898.2 million with respect to the Toshiba Settlement Agreement as of December 31, 2017, to be amortized over time in order to align with the manner in which the settlement proceeds are used to reduce debt service payments.

In the event that the principal maturities of the indebtedness described above changed materially, the amortization will be adjusted to better align with the new maturities. As such, the $4.211 billion impairment write-off was adjusted to $3.697 billion as of December 31, 2021, to account for a decrease of $40.2 million for adjustments after year end 2017 and amortization of $473.8 million. The $898.2 million deferred inflow with respect to the Toshiba Settlement Agreement was similarly adjusted to $251.1 million to account for $13.8 million in interest income and amortization of $660.9 million.

The following table summarizes the nuclear-related regulatory items:

Regulatory Item	Classification	Original Amount	2018 - 2021 Amortization	2018 - 2021 Changes	2021 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($ 473.8 million)	($40.2 million)	$ 3.697 billion
Nuclear post-suspension interest	Asset	$ 37.1 million			$ 37.1 million
Toshiba Settlement Agreement	Deferred Inflow	$898.2 million	($ 660.9 million)	$ 13.8 million	$251.1 million

Switchyard Assets. SCE&G and the Authority determined that certain transmission-related switchyard assets that were part of Summer Nuclear Units 2 and 3 (the "Switchyard Assets") were unimpaired. During 2018, SCE&G (now Dominion) and the Authority agreed that the ownership interest in the Switchyard Assets needed to be adjusted and began negotiating an agreement to adjust the percentages and true-up the charges. In June of 2019, Dominion and the Authority entered into a Bill of Sale setting the amount of the true-up payment for the Switchyard Assets at $2,675,911. Dominion made this payment to the Authority in September 2019.

Forbearance Agreement. In December of 2018, SCE&G and the Authority executed a Forbearance Agreement (the "Forbearance Agreement") for the purpose of facilitating the possible domestic and international sales of equipment, commodities and plant components relative to Summer Nuclear Units 2 and 3. Pursuant to the Forbearance Agreement, SCE&G reaffirmed its irrevocable waiver of any and all rights in certain assets (the "Forbearance Assets") consisting of Summer Nuclear Units 2 and 3; ancillary facilities; intellectual property; equipment and materials on-site and off-site including, without limitation, assets, materials and equipment that are affixed to the real property at the site but are capable of being removed. Excluded from the Forbearance Assets were the underlying real property; certain specifically-identified assets excluded from the abandonment of Summer Nuclear Units 2 and 3 prior to December 31, 2017; substation and switchyard assets; the old New Nuclear Deployment (NND) building and nuclear fuel. Under the Forbearance Agreement, Dominion had thirty (30) days from the execution date to: (i) seek approval of the Forbearance Agreement from the PSC and (ii) take reasonable efforts to obtain the release of any security interest or mortgage attached to the Forbearance Assets. In March of 2019, (i) the PSC approved the Forbearance Agreement and (ii) Dominion provided the Authority with a fully-executed release.

Sales of Summer Nuclear Units 2 and 3 Assets. During calendar years 2018 - 2021, the Authority sold certain equipment and commodities to third parties. Through December 31, 2021, $35.8 million of materials have been sold.

In accordance with the settlement agreement reached between Westinghouse Electric Company, LLC ("WEC") and the Authority in August 2020 (the Westinghouse Settlement Agreement"), the Authority owns all of the non-nuclear equipment and that proceeds from sales of nuclear-related equipment will be split between WEC and the Authority as provided in the Westinghouse Settlement Agreement as follows:

(1) Major non-installed nuclear equipment, 50% Authority and 50% WEC;
(2) Major installed nuclear equipment, 90% Authority and 10% WEC;
(3) Any other equipment that could be used in nuclear projects, 67% to the Authority and 33% to WEC.

In late 2020, the Authority entered into agreements with three outside entities to assist with the sale of surplus nuclear assets associated with Summer Nuclear Units 2 & 3. These assets are categorized as "subject" and "other" equipment, pursuant to the agreement with WEC. Following the first agreement, WEC will be solely responsible for marketing and sales of "subject" equipment. A second agreement was entered into with a large-scale utility, currently in the construction phase of two similar AP-1000 units. This agreement allows sales of "other" assets directly to the large-scale utility from the Authority. The third agreement is between the Authority and a global industrial sales company, specializing in investment recovery for surplus assets, to market and sell "other" equipment. Direct sales of "other" equipment to the large-scale utility are excluded from the agreement with the industrial sales company. In all three agreements, the Authority maintains approval privileges to all sales.

The Authority currently expects to use amounts received from the proceeds from the sale of nuclear-related equipment to pay down a portion of its outstanding debt.

Financing Activities

In 2021, Santee Cooper took advantage of the low interest rate environment. Santee Cooper priced its 2021A and 2021B Revenue Obligation transaction on August 25 and closed on September 2, 2021. This transaction totaled $430.3 million in Revenue Obligation Bonds which consisted of $145.7 million 2021 Tax-Exempt Refunding Series A and $284.6 million 2021 Tax-Exempt Improvement Series B. The 2021A Bonds mature in the years 2022 – 2036 and the 2021B Bonds mature in the years 2022 – 2051. The 2021A proceeds refunded $174.4 million of bonds.

Approximately $189 million of these new money proceeds was used to pay down commercial paper and direct purchase loans issued for capital projects expenditures from April 2019 through July 31, 2021. The remaining proceeds will be used for future capital expenditures through February 2023. This transaction produced approximately $57.0 million in cash flow savings and $50.0 million in net present value debt service savings.

Liquidity and Capital Resources

The Authority has significant cash flow from operating activities, access to capital markets, bank facilities and special funds deposit balances.

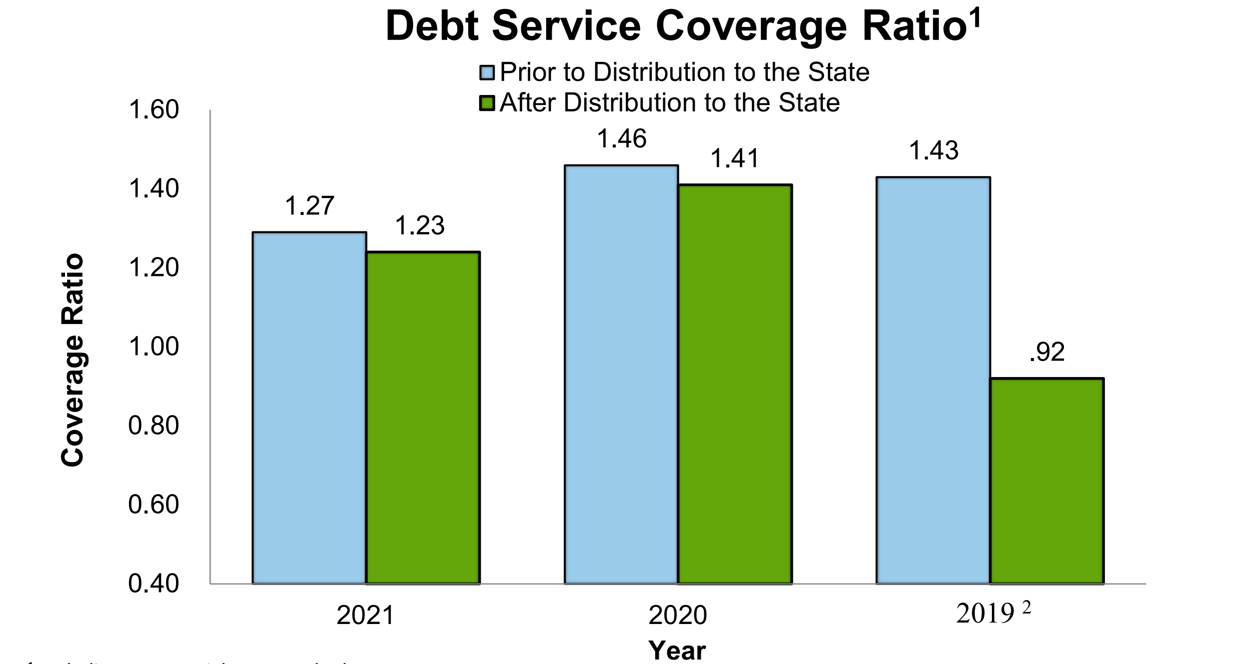
At December 31, 2021, the Authority had $974.6 million of cash and investments, of which $603.1 million was available for liquidity purposes to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $244.9 million.

The Authority has entered into a Reimbursement Agreement and secured an irrevocable direct-pay letter of credit with Barclays Bank PLC to support the issuance of commercial paper notes totaling $300.0 million as of December 31, 2021. As of December 31, 2021, the Authority had $120.8 million of commercial paper notes outstanding.

To obtain other funds, if needed, the Authority has entered into Revolving Credit Agreements with Bank of America N.A., TD Bank, N.A., and JP Morgan Chase Bank, N.A. These agreements allow the Authority to borrow up to a total of $500.0 million and expire at various dates. At December 31, 2021, the Authority had borrowings totaling $22.2 million outstanding under the Direct Purchase Revolving Credit Agreements.

DEBT SERVICE COVERAGE

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2021, 2020 and 2019 is shown below:



[1] Excluding commercial paper and other.

[2] The Authority's $200 million obligation to the common benefit fund under the Cook Settlement was accrued as a liability and recorded as a special item in 2019 (See Note 10 - *Legal Matters*). Cash payments of the liability are being paid in three annual installments in each of the third quarters of 2020, 2021 and 2022, in the amount of $65 million, $65 million, and $70 million, respectively.

BOND RATINGS

Bond ratings assigned by various agencies as of December 31, 2021, 2020 and 2019 were as follows:

Agency / Lien Level	**2021**	2020	2019
Fitch Ratings			
Revenue Obligations	**A-**	A-	A-
Commercial Paper[1]	**F1**	F1	F1+
Outlook	**Stable**	Stable	Negative
Moody's Investors Service, Inc.			
Revenue Obligations	**A2**	A2	A2
Commercial Paper[1]	**F1**	P-1	P-1
Outlook	**Stable**	Stable	Negative
Standard & Poor's Rating Services			
Revenue Obligations	**A**	A	A+
Commercial Paper[1]	**A-1**	A-1	A-1
Outlook	**Stable**	Negative	Negative

[1] In 2020, the Authority entered into Direct Pay Letters of Credit issued by Barclay's Bank, PLC various banks supporting the commercial paper program. The banks issuing the Letters of Credit have various ratings assigned by the rating agencies.

Bond Market Transactions for Years 2021, 2020 and 2019

YEAR 2021

Revenue Obligations:	**2021 Tax-Exempt Refunding Series A**	**Par Amount:**	$	145,735,000
Purpose:	Refund all the 2011 Refunding Series C and a portion of the 2012 Refunding Series A	**Date Closed:**		September 2, 2021
Comments:	Tax-exempt bond with an all-in true interest cost of 2.10 percent.			
Revenue Obligations:	**2021 Tax-Exempt Improvement Series B**	**Par Amount:**	$	284,555,000
Purpose:	To finance a portion of the Authority's ongoing capital program and convert variable debt to fixed-rate debt at a low interest rate	**Date Closed:**		September 2, 2021
Comments:	Tax-exempt bond with an all-in true interest cost 2.93 percent			

YEAR 2020

Revenue Obligations:	2020 Tax-Exempt Refunding and Improvement Series A	Par Amount:	$	338,480,000
Purpose:	To finance a portion of the Authority's ongoing capital program, refund all of the 2010 Refunding Series B and refund a portion a portion of the following: 2009 Refunding Series A, 2014 Refunding Series C, 2016 Refunding Series A, 2016 Series B	Date Closed:		November 5, 2020
Comments:	Tax-exempt bond with an all-in true interest cost of 3.03 percent.			
Revenue Obligations:	2020 Taxable Refunding Series B	Par Amount:	$	299,725,000
Purpose:	Refund a portion of the following: 2012 Refunding Series A & 2012 Series D	Date Closed:		November 5, 2020
Comments:	Taxable bond with an all-in true interest cost of 2.51 percent			

YEAR 2019

Variable Rate Revenue Obligations:	2019 Tax-Exempt Refunding Series A	Par Amount:	$	163,005,000
Purpose:	Refund all 2004 Series M through 2016 Series M1 Current Interest-Bearing Bonds and Capital Appreciation Bonds.	Date Closed:		November 21, 2019
Comments:	Tax-exempt bonds that will bear interest at weekly rates.			

Requests For Information

This financial report is designed to provide a general overview of the South Carolina Public Service Authority's finances for all those with an interest in the South Carolina Public Service Authority's finances. Questions concerning any of the information provided in this report or requests for additional information should be addressed to Daniel T. Manes, Controller, South Carolina Public Service Authority, P.O. Box 2946101, Moncks Corner, SC 29461-6106.

Statements of Net Position - Business - Type Activities

South Carolina Public Service Authority
As of December 31, 2021 and 2020

		2021		2020
		(Thousands)		
ASSETS				
Current assets				
Unrestricted cash and cash equivalents	**$**	**299,487**	$	252,782
Unrestricted investments		**303,625**		189,211
Restricted cash and cash equivalents		**36,630**		58,500
Restricted investments		**182,343**		113,772
Receivables, net of allowance for doubtful accounts of $2,560 and $2,382 at December 31, 2021 and 2020, respectively		**175,810**		210,163
Materials inventory		**152,950**		151,503
Fuel inventory				
Fossil fuels		**54,011**		74,680
Nuclear fuel - net		**105,747**		108,340
Interest receivable		**1,344**		1,426
Regulatory assets - nuclear		**36,482**		6,497
Prepaid expenses and other current assets		**52,119**		28,475
Total current assets		**1,400,548**		1,195,349
Noncurrent assets				
Restricted cash and cash equivalents		**269**		803
Restricted investments		**152,254**		154,077
Capital assets				
Utility plant		**8,800,734**		8,572,695
Long lived assets - asset retirement cost		**266,981**		269,662
Accumulated depreciation		**(4,422,072)**		(4,252,077)
Total utility plant - net		**4,645,643**		4,590,280
Construction work in progress		**331,065**		447,309
Other physical property - net		**26,492**		27,636
Investment in associated companies		**21,956**		9,501
Costs to be recovered from future revenue		**222,986**		219,840
Regulatory asset - OPEB		**152,497**		152,497
Regulatory assets - nuclear		**3,697,704**		3,734,186
Other noncurrent and regulatory assets		**189,320**		124,247
Total noncurrent assets		**9,440,186**		9,460,376
Total assets	**$**	**10,840,734**	$	10,655,725
DEFERRED OUTFLOWS OF RESOURCES				
Deferred outflows – pension	**$**	**53,010**	$	43,199
Deferred outflow - OPEB		**49,090**		42,276
Regulatory asset-asset retirement obligation		**672,804**		691,641
Accumulated decrease in fair value of hedging derivatives		**11,264**		18,634
Unamortized loss on refunded and defeased debt		**86,398**		99,969
Total deferred outflows of resources	**$**	**872,566**	$	895,719
Total assets & deferred outflows of resources	**$**	**11,713,300**	$	11,551,444

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

Statements of Net Position - Business - Type Activities (continued)

South Carolina Public Service Authority
As of December 31, 2021 and 2020

	2021	2020
	(Thousands)	
LIABILITIES		
Current liabilities		
Current portion of long - term debt	**$ 107,791**	$ 104,575
Accrued interest on long - term debt	**38,324**	37,919
Revolving credit agreement	**3,211**	26,100
Commercial paper	**120,832**	171,251
Accounts payable	**187,979**	137,452
Other current liabilities	**213,750**	137,631
Total current liabilities	**671,887**	614,928
Noncurrent liabilities		
Construction liabilities	**2,286**	2,963
Net OPEB liability	**189,328**	176,109
Net pension liability	**294,504**	344,795
Asset retirement obligation liability	**669,419**	694,236
Total long-term debt (net of current portion)	**6,554,026**	6,514,572
Unamortized debt discounts and premiums	**407,565**	342,705
Long-term debt-net	**6,961,591**	6,857,277
Other credits and noncurrent liabilities	**85,362**	161,302
Total noncurrent liabilities	**8,202,490**	8,236,682
Total liabilities	**$ 8,874,377**	$ 8,851,610
DEFERRED INFLOWS OF RESOURCES		
Deferred inflows - pension	**$ 75,525**	$ 27,004
Deferred inflow - OPEB	**9,388**	14,129
Accumulated increase in fair value of hedging derivatives	**118,208**	14,767
Nuclear decommissioning costs	**245,933**	247,903
Regulatory inflows – Toshiba settlement	**251,089**	296,380
Total deferred inflows of resources	**$ 700,143**	$ 600,183
NET POSITION		
Net investment in capital assets	**$ 2,010,384**	$ 2,090,633
Restricted for debt service	**9,214**	12,107
Restricted for capital projects	**0**	119
Unrestricted (deficit)	**119,182**	(3,208)
Total net position	**$ 2,138,780**	$ 2,099,651
Total liabilities, deferred inflows of resources & net position	**$ 11,713,300**	$ 11,551,444

Statements of Revenues, Expenses and Changes in Net Position - Business - Type Activities
South Carolina Public Service Authority
Years Ended December 31, 2021 and 2020

	2021	2020
	(Thousands)	
Operating revenues		
Sale of electricity	$ 1,740,759	$ 1,602,348
Sale of water	8,705	9,075
Other operating revenue	16,321	16,004
Total operating revenues	1,765,785	1,627,427
Operating expenses		
Electric operating expenses		
Production	156,700	150,203
Fuel	466,191	426,323
Purchased and interchanged power	303,924	171,313
Transmission	32,279	30,027
Distribution	11,606	11,096
Customer accounts	16,248	15,651
Sales	1,655	6,400
Administrative and general	81,126	95,791
Electric maintenance expenses	158,308	102,487
Water operating expenses	3,726	3,798
Water maintenance expenses	918	899
Total operating and maintenance expenses	1,232,681	1,013,988
Depreciation	259,075	244,992
Sums in lieu of taxes	4,530	4,703
Total operating expenses	1,496,286	1,263,683
Operating income	269,499	363,744
Nonoperating revenues (expenses)		
Interest and investment revenue	2,075	3,216
Net increase (decrease) in the fair value of investments	(1,558)	148
Interest expense on long-term debt	(313,175)	(321,682)
Interest expense on commercial paper and other	(6,306)	(7,295)
Amortization income	14,535	9,385
Costs to be recovered from future revenue	3,146	(54,431)
U.S. Treasury subsidy on Build America Bonds	7,703	7,652
Regulatory Amortization - net	45,331	27,429
Other - net	35,014	23,888
Total nonoperating revenues (expenses)	(213,235)	(311,690)
Income before transfers	56,264	52,054
Transfers		
Distribution to the State	(17,135)	(17,479)
Change in net position	39,129	34,575
Net position – beginning of period	2,099,651	2,065,076
Total net position – ending	$ 2,138,780	$ 2,099,651

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

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Statements of Cash Flows - Business - Type Activities

South Carolina Public Service Authority
Years Ended December 31, 2021 and 2020

	2021	2020
Cash flows from operating activities		(Thousands)
Receipts from customers	$ **1,799,960**	$ 1,618,250
Payments to non - fuel suppliers	**(395,367)**	(629,184)
Payments for fuel	**(455,810)**	(419,359)
Purchased power	**(303,921)**	(171,313)
Payments to employees	**(171,483)**	(195,941)
Other receipts-net	**196,624**	384,725
Net cash provided by operating activities	**670,003**	587,178
Cash flows from non-capital related financing activities		
Distribution to the State	**(17,135)**	(17,479)
Repayment of revolving credit agreement draw	**0**	(35,766)
Proceeds from issuance of commercial paper notes	**500**	0
Repayment of commercial paper notes	**(16,392)**	(12,283)
Refunding/defeasance of long-term debt	**0**	(569,555)
Proceeds from sale of bonds	**0**	342,879
Repayment of long - term debt	**(6,644)**	(130)
Interest paid on long - term debt	**(186,670)**	(185,684)
Interest paid on commercial paper and other	**(1,294)**	(3,610)
Bond issuance and other related costs	**(814)**	(10,553)
Net cash used in non-capital related financing activities	**(228,449)**	(492,181)
Cash flows from capital-related financing activities		
Proceeds from revolving credit agreement draw	**0**	175,100
Repayment of revolving credit agreement draw	**(22,889)**	(138,500)
Proceeds from issuance of commercial paper notes	**65,160**	63,636
Repayment of commercial paper notes	**(99,687)**	(22,453)
Refunding/defeasance of long-term debt	**(282,925)**	(57,315)
Proceeds from sale of bonds	**430,290**	295,326
Repayment of long-term debt	**(98,051)**	(89,155)
Interest paid on long-term debt	**(123,949)**	(128,655)
Interest paid on commercial paper and other	**(4,858)**	(4,586)
Construction and betterments of utility plant	**(204,506)**	(151,370)
Bond issuance and other related costs	**91,384**	34,634
Other-net	**7,378**	(3,046)
Net cash used in capital related financing activities	**(242,653)**	(26,384)
Cash flows from investing activities		
Proceeds from the sale and maturity of investment securities	**973,410**	950,123
Purchase of investment securities	**(1,154,572)**	(1,075,102)
Unrealized gains (losses) on investments	**1,558**	(148)
Interest on investments	**5,004**	2,851
Net cash used in investing activities	**(174,600)**	(122,276)
Net increase (decrease) in cash and cash equivalents	**24,301**	(53,663)
Cash and cash equivalents - beginning	**312,085**	365,748
Cash and cash equivalents - ending	$ **336,386**	$ 312,085

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

Statements of Cash Flows - Business - Type Activities (continued)

South Carolina Public Service Authority
Years Ended December 31, 2021 and 2020

	2021	2020
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	$ 269,499	$ 363,744
Adjustments to reconcile operating income to net cash provided by operating activities		
Depreciation	259,075	244,992
Amortization of nuclear fuel	16,445	20,245
Regulatory amortization – net	45,331	27,429
Cost to be recovered from future revenue	3,146	(54,431)
Amortization of debt discount and expense	(23,926)	(23,530)
Amortization of loss on reacquired debt	9,360	14,099
Net power losses involving associated companies	(81,001)	(32,440)
Distributions from associated companies	82,860	27,873
Advances to/from associated companies	14,253	(2,651)
Other income and expenses	21,110	34,788
Changes in assets and liabilities		
Accounts receivable - net	34,353	(9,126)
Inventories	19,222	50,417
Prepaid expenses	(24,693)	47,884
Other deferred debits	(92,152)	25,001
Cost to be recovered from future income	(3,146)	54,431
Unamortized loss on refunded and defeased debt	(9,360)	(14,099)
Accounts payable	54,617	(18,594)
Other current liabilities	102,944	(22,808)
Unamortized debt discounts and premiums	23,926	23,530
Other noncurrent liabilities	(51,860)	(169,576)
Net cash provided by operating activities	$ 670,003	$ 587,178
Composition of cash and cash equivalents		
Current		
Unrestricted cash and cash equivalents	$ 299,487	$ 252,782
Restricted cash and cash equivalents	36,630	58,500
Noncurrent		
Restricted cash and cash equivalents	269	803
Cash and cash equivalents at the end of the year	$ 336,386	$ 312,085
Noncash capital activities - Accounts Payable	$ 6,262	$ 10,352

Statements of Fiduciary Net Position - OPEB Trust Fund
South Carolina Public Service Authority
As of December 31, 2021, and 2020

		2021		2020
		(Thousands)		
ASSETS				
Cash and cash equivalents	**$**	**1,367**	$	841
Investments		**108,376**		102,900
Total current assets		**109,743**		103,741
Total assets	**$**	**109,743**	$	103,741
LIABILITIES				
Total liabilities	**$**	**0**	$	0
NET POSITION				
Restricted for other postemployment benefits (OPEB)	**$**	**109,743**	$	103,741
Total net position	**$**	**109,743**	$	103,741
Total liabilities & net position	**$**	**109,743**	$	103,741

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

Statements of Changes in Fiduciary Net Position - OPEB Trust Fund

South Carolina Public Service Authority

Years Ended December 31, 2021 and 2020

		2021		2020
		(Thousands)		
ADDITIONS				
Employer contributions	**$**	**7,691**	$	10,571
Total employer contributions		**7,691**		10,571
Investment income (loss)				
Appreciation (depreciation) in fair value of investments		**(4,147)**		2,445
Interest		**2,458**		2,378
Net investment income (loss)		**(1,689)**		4,823
Total additions		**6,002**		15,394
DEDUCTIONS				
Total deductions		**0**		0
Change in net position		**6,002**		15,394
Net position - beginning of period		**103,741**		88,347
Total net position - ending	**$**	**109,743**	$	103,741

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

NOTES

Note 1 – Summary of Significant Accounting Policies

A - Reporting Entity - The South Carolina Public Service Authority (the "Authority" or "Santee Cooper"), a component unit of the State of South Carolina (the "State"), was created in 1934 by the State legislature. The Santee Cooper Board of Directors (the "Board") is appointed by the Governor of South Carolina with the advice and consent of the Senate. The purpose of the Authority is to provide electric power, wholesale water, and broadband services to the people of South Carolina. Capital projects are funded by bonds, commercial paper and internally generated funds. As authorized by State law, the Board sets rates charged to customers to pay debt service and operating expenses and to provide funds required under bond covenants. The Authority's financial statements include the accounts of the electric system and the Lake Moultrie and Lake Marion Regional Water Systems after elimination of inter-company accounts and transactions.

B - System of Accounts - The accounting records of the Authority are maintained on an accrual basis in accordance with accounting principles generally accepted in the United States ("GAAP") issued by the Governmental Accounting Standards Board ("GASB") applicable to governmental entities that use proprietary fund accounting.

The accounts are maintained substantially in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") for the electric system and the National Association of Regulatory Utility Commissioners ("NARUC") for the water systems.

The Authority also complies with policies and practices prescribed by its Board and practices common in both industries. As the Board is authorized to set rates, the Authority follows GASB 62. This standard provides for the reporting of assets and liabilities consistent with the economic effect of the rate structure.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions in the Authority's reporting. This practice affects the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

C - Current and Noncurrent - The Authority presents assets and liabilities in order of relative liquidity. The liquidity of an asset is determined by how readily it is expected to be converted to cash and whether restrictions limit the use of the resources. The liquidity of a liability is based on its maturity, or when cash is expected to be used to liquidate the liability.

D - Restricted Assets - For purposes of the Statements of Net Position and Statements of Cash Flows, assets are restricted when constraints are placed on their use by either:

(1) External creditors, grantors, contributors, or laws or regulations of other governments; or
(2) Law through constitutional provisions or enabling legislation.

Assets not meeting the requirements of restricted or net investment in capital assets are classified as unrestricted.

E - Cash and Cash Equivalents - For purposes of the Statements of Net Position and Statements of Cash Flows, the Authority considers highly liquid investments with original maturities of ninety days or less, and cash on deposit with financial institutions, as unrestricted and restricted cash and cash equivalents.

F - Inventory - Material and fuel inventories are carried at weighted average costs. At the time of issuance or consumption, an expense is recorded at the weighted average cost.

G - Utility Plant - Utility plant is recorded at cost, which includes materials, labor, overhead and interest capitalized during construction. Interest was capitalized in fiscal 2020 based on the interest rate applied through borrowings; interest was not capitalized in fiscal 2021 due to the adoption of GASB 89, Accounting for Interest Cost Incurred Before the End of a Construction Period. Interest capitalized totaled $0 and $935,943 in 2021 and 2020, respectively. The costs of maintenance, repairs and minor replacements are charged to appropriate operation and maintenance expense accounts. The costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

H - Depreciation - Depreciation is computed using composite rates on a straight-line basis over the estimated useful lives of the various classes of the plant. Composite rates are applied to the gross plant balance of various classes of assets which includes appropriate adjustments for cost of removal and salvage. In 2019, the Authority commissioned an independent party to perform a depreciation study to assist management in establishing appropriate composite depreciation rates. Based on the completed depreciation study, new depreciation rates were used for 2020 for assets, and those rates continued to be applicable in 2021. For assets not grouped in a plant class, straight-line depreciation is used over the estimated useful life of the asset.

Annual depreciation provisions, expressed as a percentage of average depreciable utility plant in service, were as follows:

Years Ended December 31,	**2021**	2020
Annual average depreciation percentages	**3.0%**	3.0%

I - Retirement of Long Lived Assets - The Authority follows the guidance of GASB 83, *Certain Asset Retirement Obligations,* in regard to the decommissioning of V.C. Summer Nuclear Station ("Summer Nuclear Unit 1") and for closing coal-fired generation ash ponds. The requirements for both were recorded within capital assets on the accompanying Statements of Net Position.

Summer Nuclear Unit 1

As required by the Nuclear Regulatory Commission ("NRC") and in accordance with prudent utility practices, Santee Cooper systematically sets aside funds to provide for the eventual decommissioning of Summer Nuclear Unit 1. The annual decommissioning funding deposit amount is currently based on NRC requirements, estimated cost escalation and fund earnings rates, the results of a site-specific decommissioning study conducted by TLG Services, Inc. in 2019, estimated Department of Energy ("DOE") reimbursement of spent fuel energy storage costs and a SAFSTOR (delayed decommissioning) scenario. This site-specific study also forms the basis for the asset retirement obligation calculation presented in the table below. The estimated remaining useful life of Summer Nuclear Unit 1 is expected to end in 2062.

Ash Ponds

The Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash, and gypsum. These wastes, known as Coal Combustion Residuals ("CCRs"), are exempt from hazardous waste regulation under the Resource Conservation and Recovery Act ("RCRA"). On April 17, 2015, EPA published the CCR Rule establishing comprehensive requirements for the management and disposal of CCRs. The Rule regulates CCRs as a RCRA Subtitle D, nonhazardous waste and had an effective date of October 19, 2015. The Authority continues to comply with the CCR Rule through groundwater monitoring, assessment of corrective measures and internet postings of CCR Rule reports. Long-term compliance plans to address groundwater include pond closures and utilization of Class 3 landfills at the Cross and Winyah Generating Stations for disposal of CCRs.

The Authority has ash ponds at Cross, Winyah, Jefferies Generating Stations and gypsum ponds at Cross and Winyah Generating Stations. Closure plans for the Jefferies Generating Station ash ponds and for the Winyah West Ash Pond have been approved by the Department of Health and Environmental Control ("DHEC") and closure is in progress, with regulatory deadlines of 2030. These ponds are currently not subject to the CCR Rule. However, CCR rulemakings changes could regulate inactive impoundments at closed facilities which could result in the Jefferies A ash pond and possibly the now closed Grainger ash ponds being subject to the CCR Rule. The Cross Bottom Ash Pond and the remaining ponds at the Winyah Generating Station (A Ash Pond, B Ash Pond, South Ash Pond and Unit 3 & 4 Slurry Pond) are subject to the CCR Rule's closure requirements and are subject to DHEC closure regulations. Plans are being developed and implemented to facilitate closure of the remaining ponds by the CCR Rule's regulatory deadlines. The ponds will be closed through excavation and beneficial use of materials or through disposal in the on-site industrial Class 3 solid waste landfills. Two additional ponds (Winyah Slurry Pond 2 and the Cross Gypsum Pond) are also subject to the CCR Rule and have already completed closure in accordance with DHEC's requirements. Volumetric calculations were conducted by the Authority to determine estimated volumes to be removed. Cost estimates were then applied to the volumes to estimate the asset retirement obligation as presented in the table below.

The asset retirement obligation ("ARO") is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes the Authority's transactions:

Years Ended December 31,		**2021**			2020	
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 427.5**	**$ 266.7**	**$ 694.2**	$ 437.5	$ 280.3	$ 717.8
Accretion expense	**12.0**	**(36.8)**	**(24.8)**	(10.0)	(13.6)	(23.6)
Balance as of December 31,	**$ 439.5**	**$ 229.9**	**$ 669.4**	$ 427.5	$ 266.7	$ 694.2
Asset Retirement Cost (ARC):	**$ 96.5**	**$ 170.4**	**$ 266.9**	$ 96.5	$ 173.1	$ 269.6
Regulatory Asset - ARO	**$ 444.7**	**$ 228.1**	**$ 672.8**	$ 426.8	$ 264.9	$ 691.7

J – Closure and Post Closure Care Costs - The Authority follows the guidance of GASB 18, *Accounting for Municipal Solid Waste Landfill Closure and Post-closure Care Costs*, in accounting for the closure and post-closure care costs associated with Cross and Winyah Generating Stations landfills (the "landfills"). State and federal laws and regulations require the Authority to place a final cover on its landfills when it stops accepting waste and to perform certain maintenance and monitoring functions at the site for thirty years after closure. Although closure and post-closure care costs will be paid only near or after the date the landfill stops accepting waste, the Authority reports a portion of these closure and post-closure care costs as an operating expense in each period based on landfill capacity used as of each balance sheet date. The landfill closure and post-closure expenses at December 31, 2021 and 2020 were $11.9 million and $4.5 million, respectively, which are included as part of electric operating expenses, and represent a cumulative amount reported to date based on the use of 16% of the total permitted capacity of the Cross Landfill Area 1B and 63% of the total permitted capacity of the Winyah Landfill Area 1. The Authority will recognize the remaining estimated cost of closure and post-closure care for these landfill areas of $19.7 million as the remaining estimated capacity is filled. These amounts are based on what it would cost to perform all closure and post-closure care in 2021. The landfill closure and post-closure care liabilities at December 31, 2021 and 2020 were $10.9 million and $4.5 million, respectively, after 2021 closure activity reduced the liability balance. Based on current fill rates, the Authority expects to close the existing Cross landfill cell in 2058. Future, already permitted landfill cells will be constructed, operated, and then closed on an on-going basis, as needed for the life of the plant. Based on current fill rates, the Authority expects to close the Winyah Landfill Area 1 in 2023. Future, already permitted landfill cells will be constructed, operated, and then closed once pond closure activities are complete and the Winyah units are retired. Thus, closure of the Winyah Landfill Area 2 is expected to be complete by 2035. Actual closure costs may be higher due to inflation, changes in technology, or changes in regulations.

In 2021, the Authority has met the requirements of a local government financial test that is one option under State and federal laws and regulations to help determine if a unit is financially able to meet closure and post closure care requirements.

K - Reporting Impairment Losses - The Authority follows the guidance of GASB 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*, in determining if a capital asset has been impaired and the accounting treatment of such impairment. An impairment is a significant, unexpected decline in the service utility of a capital asset. Events or changes in circumstances that may be indicative of impairment include evidence of physical damage, enactment or approval of laws or regulations or other changes in environmental factors, technological changes or evidence of obsolescence, changes in the manner or duration of use of a capital asset, and construction stoppage. A capital asset generally should be considered impaired if both (a) the decline in service utility of the capital asset is large in magnitude and (b) the event or change in circumstance is outside the normal life cycle of the capital asset. Impaired capital assets that will no longer be used should be reclassified from plant balances and CWIP to another asset category and reported at the lower of carrying value or fair value.

There were no new impairment losses for 2021 or 2020.

L- Other Regulatory Items - In accordance with GASB 62's guidance on regulated operations, regulated accounting rules may be applied to business type activities that have regulated operations if certain criteria are met. GASB 65, paragraph 29, further clarified regulatory accounting rules under GASB 62. Under regulatory accounting a regulated utility may defer recognition of expenses or revenues if certain criteria are met and the revenues and expenses will be included in future rates. Significant regulatory items are presented as follows:

Regulatory Assets - Summer Nuclear Units 2 and 3
On December 11, 2017, the Board approved the use of regulatory accounting for a portion of the nuclear post-suspension interest balance of $37.1 million. As of December 31, 2021, the balance remained the same and the amortization of the regulatory asset will not begin until 2022.

Based on a Board resolution dated January 22, 2018, the use of regulatory accounting was approved for costs incurred related to the impairment of Summer Nuclear Units 2 and 3. The Board gave approval to write-off the total asset balance of $4.205 billion and use regulatory accounting to align with the debt service collected in rates. Accordingly, $6.5 million and $0.8 million was amortized in 2021 and 2020, respectively. The remaining balance outstanding at December 31, 2021 was $3.697 billion.

Regulatory Liability – Toshiba Settlement Agreement.
The Board of Directors approved a resolution dated December 11, 2017, authorizing use of regulatory accounting to defer recognition of income from the Toshiba Settlement Agreement. As a result, the Authority recorded a regulatory deferred inflow of $898.2 million. The deferred inflow will be amortized to align with the manner in which debt service is reduced as a result of using the proceeds. During 2021 and 2020 $45.3 million and $69.8 million, respectively was amortized. The remaining balance outstanding at December 31, 2021 was $251.1 million.

Unfunded OPEB Liability
On October 13, 2017, the Board approved the use of regulatory accounting to offset the initial unfunded OPEB liability resulting from implementation of GASB 75. As a result, the Authority recorded a regulatory asset of $165.2 million. The regulatory asset will be amortized to expense in accordance with a Level Dollar, 30-year closed amortization period funding schedule provided by the Actuary. The remaining balance outstanding at December 31, 2021 was $152.5 million.

M - Investment in Associated Companies - The Authority is a member of The Energy Authority ("TEA"). Approximate ownership interests in TEA as of December 31, 2021 and 2020 were as follows:

Years Ended December 31,	**2021**	2020
Owners	Ownership (%)	
City Utilities of Springfield (Missouri)	**5.88**	5.88
Gainesville Regional Utilities (Florida)	**5.88**	5.88
American Municipal Power (Ohio)	**17.65**	17.65
JEA (Florida)	**17.65**	17.65
MEAG Power (Georgia)	**17.65**	17.65
Nebraska Public Power District (Nebraska)	**17.65**	17.65
Santee Cooper (South Carolina)	**17.65**	17.65
Total	**100.00**	100.00

TEA markets wholesale power and coordinates the operation of the generation assets of its members to maximize the efficient use of electrical energy resources, reduce operating costs and increase operating revenues of the members. It is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. TEA does not engage in the construction or ownership of generation or transmission assets. In addition, it assists members with fuel hedging activities and acts as an agent in the execution of forward transactions. The Authority accounts for its investment in TEA under the equity method of accounting.

All of TEA's revenues and costs are allocated to the members. The following table summarizes the transactions applicable to the Authority:

Years Ended December 31,		**2021**		2020
		(Thousands)		
TEA Investment:				
Balance as of January 1,	**$**	**9,422**	$	7,604
Reduction to power costs and increases in electric revenues		**95,272**		29,291
Less: Distributions from TEA		**82,860**		27,873
Less: Other (includes equity losses)		**0**		(400)
Balance as of December 31,	**$**	**21,834**	$	9,422
Due To/Due From TEA:				
Payable to	**$**	**66,037**	$	17,398
Receivable from	**$**	**11,735**	$	1,455

The Authority's exposure relating to TEA is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. Upon the Authority making any payments under its electric guarantee, it has certain contribution rights with the other members in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's equity ownership interest. After such contributions have been affected, the Authority would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the Authority has the ability to terminate its guarantee obligations by providing advance notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The Authority's support of TEA's trading activities is limited based on the formula derived from the forward value of TEA's trading positions at a point in time. The formula was approved by the Authority's Board**.** At December 31, 2021, the trade guarantees are an amount not to exceed Santee Cooper's share of approximately $51.6 million.

The Authority is also a member of TEA Solutions. TEA Solutions is a publicly supported non-profit corporation. Members and ownership interests in TEA Solutions as of December 31, 2021 and 2020 were as follows:

Years Ended December 31,	**2021**	2020
Owners	Ownership (%)	
American Municipal Power (Ohio)	**25.0**	25.0
JEA (Florida)	**25.0**	25.0
MEAG Power (Georgia)	**25.0**	25.0
Santee Cooper (South Carolina)	**25.0**	25.0
Total	**100.0**	100.0

TEA Solutions was formed mainly to (1) coordinate the operation of electric generation resources and the purchase and sale of electric power on behalf of the corporation's clients; (2) coordinate the purchase and sale of natural gas relating to fuel for clients' generation of electric energy or relating to clients' operation of a retail gas distribution system; and (3) provide consulting and software services to clients.

The Authority funded its initial share of TEA Solutions with a $150,000 contribution in 2013. This contribution was to cover legal, consulting and other start-up costs pertaining to TEA Solutions. The Authority's exposure relating to TEA Solutions is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. The balance in its member equity account at December 31, 2021 and 2020 was approximately $122,525 and $98,035, respectively.

N - Deferred Outflows / Deferred Inflows of Resources - In addition to assets, the Statements of Net Position reports a separate section for Deferred Outflows of Resources. These items represent a consumption of net position that applies to a future period and until that time will not be recognized as an expense or expenditure. The Authority has five items meeting this criterion: (1) deferred outflows – pension; (2) accumulated decrease in fair value of hedging derivatives; (3) unamortized loss on refunded and defeased debt; (4) deferred outflows – OPEB; and (5) deferred outflow – asset retirement obligation.

In addition to liabilities, the Statements of Net Position also reports a separate section for Deferred Inflows of Resources. These items represent an acquisition of net position that applies to a future period and until that time will not be recognized as revenue. The Authority has five items meeting this criterion: (1) deferred inflows – pension; (2) accumulated increase in fair value of hedging derivatives; (3) nuclear decommissioning costs; (4) regulatory inflows - Toshiba settlement; and (5) deferred inflows – OPEB.
The following table summarizes the Authority's total deferred items:

Years Ended December 31,		**2021**		2020
		(Thousands)		
Deferred outflows of resources	**$**	**872,566**	$	895,719
Deferred inflows of resources	**$**	**700,143**	$	600,183

O - Accounting for Derivative Instruments - In compliance with GASB 53 and 64, the annual changes in the fair value of effective hedging derivative instruments are required to be deferred (reported as deferred outflows of resources and deferred inflows of resources on the Statements of Net Position). Deferral of changes in fair value generally lasts until the transaction involving the hedged item ends.

Core business commodity inputs for the Authority have historically been hedged in an effort to mitigate volatility and cost risk and improve cost effectiveness. Natural gas is a direct input and heating oil is used as a proxy for retail diesel fuel because it is used to power the coal trains. Unrealized gains and losses related to such activity are deferred in a regulatory account and recognized in earnings as fuel costs are incurred in the production cycle.

A summary of the Authority's derivative activity for years ended December 31, 2021 and 2020 is below:

Cash Flow Hedges and Summary of Activity

Years Ended December 31,			**2021**		2020
	Account Classification		(Millions)		
Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**91.1**	$	(6.1)
Heating oil	Regulatory assets/liabilities		**15.9**		2.3
Changes in Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**97.2**	$	43.7
Heating oil	Regulatory assets/liabilities		**13.6**		2.3
Recognized Net Gains (Losses)					
Natural gas	Operating expense-fuel	**$**	**34.2**	$	(27.3)
Heating oil	Operating expense-fuel		**5.5**		(2.2)
Realized But Not Recognized Net Gains (Losses)					
Natural gas	Regulatory assets/liabilities	**$**	**2.8**	$	(2.1)
Heating oil	Regulatory assets/liabilities		**0.5**		0.1
Notional					
			MBTUs		
Natural gas			**138,912**		127,600
			Gallons (000s)		
Heating oil			**16,037**		21,672
Maturities					
Natural gas			**Jan 2022-Dec 2026**		Jan 2021-Dec 2024
Heating oil			**Jan 2022-Dec 2024**		Jan 2021-Dec 2024

P - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers but not billed are accrued monthly. Accrued revenue for retail customers totaled $14.5 million in 2021 and $14.2 million in 2020.

Fuel costs are reflected in operating expenses as fuel is consumed. All customers are billed utilizing rates and contracts that include fuel cost recovery components. Currently most industrial, municipal, and retail fuel adjustments are under the rate freeze schedules. Once the rate freeze is completed, most fuel adjustment provisions will be based on either the accrued costs for the previous month or the actual weighted average costs for the previous three-month period. The fuel adjustment provisions are based on either the accrued costs for the previous month or the actual weighted average costs for the previous three-month period.

Rates to Central are determined in accordance with the cost of service methodology contained in the Central Agreement. Under this agreement Central initially pays monthly based on estimated rates and actual loads. The charges are then adjusted to reflect actual costs and loads, on a monthly basis for fuel and an annual basis for all other costs, and Central is charged or credited with the difference.

The Authority and Central have resolved certain matters relating to the nuclear project through the execution of the Cook Settlement and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement. Rates to Central and above provisions are impacted by Cook settlement (See Note 15 – *Cook Settlement as to Rates)*.

Q- Bond Issuance Costs and Refunding Activity - GASB 65 requires that debt issuance costs, other than prepaid insurance, be expensed in the period incurred. In order to align the impact of this pronouncement with the Authority's rate making process, in October 2012, the Board authorized the use of regulatory accounting to allow continuation of prior accounting treatment with regard to these costs.

Unamortized debt discounts and premiums are amortized to income over the terms of the related debt issues. Gains or losses on refunded and extinguished debt are amortized to earnings over the shorter of the remaining life of the refunded debt or the life of the new debt.

R- Distribution to the State - Any and all net earnings of the Authority not necessary for the prudent conduct and operation of its business in the best interests of the Authority or to pay the principal of and interest on its bonds, notes, or other evidences of indebtedness or other obligations, or to fulfill the terms and provisions of any agreements made with the purchasers or holders thereof or others must be paid over semiannually to the State Treasurer for the general funds of the State. Nothing shall prohibit the Authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis, from the combined electric and water systems. (Code of Laws of South Carolina, as amended Section 58-31-110).

Distributions made to the State in 2021 and 2020 totaled approximately $17.1 million and $17.5 million, respectively.

S - New Accounting Standards –

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 87	**Leases**	Under review
Issue Date: June 2017	Effective for Periods Beginning After: June 15, 2021	
Description:	The objective of this Statement is to better meet the information needs of financial statement users by improving accounting and financial reporting for leases by governments. This Statement increases the usefulness of governments' financial statements by requiring recognition of certain lease assets and liabilities for leases that previously were classified as operating leases and recognized as inflows of resources or outflows of resources based on the payment provisions of the contract. It establishes a single model for lease accounting based on the foundational principle that leases are financings of the right to use an underlying asset. Under this Statement, a lessee is required to recognize a lease liability and an intangible right-to-use lease asset, and a lessor is required to recognize a lease receivable and a deferred inflow of resources, thereby enhancing the relevance and consistency of information about governments' leasing activities.	

Statement No. GASB 89	**Accounting for Interest Cost Incurred before the End of a Construction Period**	Implemented in 2021
Issue Date: June 2018	Effective for Periods Beginning After: December 15, 2020	
Description:	The objectives of this Statement are (1) to enhance the relevance and comparability of information about capital assets and the cost of borrowing for a reporting period and (2) to simplify accounting for interest cost incurred before the end of a construction period. This Statement establishes accounting requirements for interest cost incurred before the end of a construction period. Such interest cost includes all interest that previously was accounted for in accordance with the requirements of paragraphs 5–22 of Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements,* which are superseded by this Statement. This Statement requires that interest cost incurred before the end of a construction period be recognized as an expense in the period in which the cost is incurred for financial statements prepared using the economic resources measurement focus. As a result, interest cost incurred before the end of a construction period will not be included in the historical cost of a capital asset reported in a business-type activity or enterprise fund . This Statement also reiterates that in financial statements prepared using the current financial resources measurement focus, interest cost incurred before the end of a construction period should be recognized as an expenditure on a basis consistent with governmental fund accounting principles.	
Statement No. GASB 91	**Conduit Debt Obligations**	Under review
Issue Date: May 2019	Effective for Periods Beginning After: December 15, 2021	
Description:	The objectives of this Statement are to provide a single method of reporting conduit debt obligations by issuers and eliminate diversity in practice associated with (1) commitments extended by issuers, (2) arrangements associated with conduit debt obligations, and (3) related note disclosures. This statement achieves those objectives by clarifying the existing definition of a conduit debt obligation; establishing that a conduit debt obligation is not a liability of the issuer; establishing standards for accounting and financial reporting of additional commitments and voluntary commitments extended by issuers and arrangements associated with conduit debt obligations; and improving required note disclosures. This statement also addresses arrangements, often characterized as leases, that are associated with conduit debt obligations. Issuers should not report those arrangements as leases, nor should they recognize a liability for the related conduit debt obligations or a receivable for the payments related to those arrangements. This statement requires issuers to disclose general information about their conduit debt obligations, organized by type of commitment, including the aggregate outstanding principal amount of the issuers' conduit debt obligations and a description of each type of commitment. Issuers that recognize liabilities related to supporting the debt service of conduit debt obligations also should disclose information about the amount recognized and how the liabilities changed during the reporting period.	
Statement No. GASB 92	**Omnibus 2020**	
Issue Date: January 2020	Effective for periods beginning after June 15, 2021	Under Review
Description:	The objectives of this Statement are to enhance comparability in accounting and financial reporting and to improve the consistency of authoritative literature by addressing practice issues that have been identified during implementation and application of certain GASB Statements. This statement addresses a variety of topics including issues related to Statement No. 87, post-employment benefits (pensions and other postemployment benefits [OPEB]), Statement No. 73, Statement No. 84, asset retirement obligations, reporting of public entity risk pools, reference to nonrecurring fair value measurements of assets or liabilities in authoritative literature, and terminology used to refer to derivative instruments.	

Statement No. GASB 93 **Replacement of Interbank Offered Rates** Under Review

Issue Date: March 2020 Effective for periods beginning after June 15, 2021

Description: Some governments have entered into agreements in which variable payments made or received depend on an interbank offered rate (IBOR)—most notably, the London Interbank Offered Rate (LIBOR). As a result of global reference rate reform, LIBOR is expected to cease to exist in its current form at the end of 2021, prompting governments to amend or replace financial instruments for the purpose of replacing LIBOR with other reference rates, by either changing the reference rate or adding or changing fallback provisions related to the reference rate.

Statement No. 53, Accounting and Financial Reporting for Derivative Instruments, as amended, requires a government to terminate hedge accounting when it renegotiates or amends a critical term of a hedging derivative instrument, such as the reference rate of a hedging derivative instrument's variable payment. In addition, in accordance with Statement No. 87, Leases, as amended, replacement of the rate on which variable payments depend in a lease contract would require a government to apply the provisions for lease modifications, including remeasurement of the lease liability or lease receivable.

The objective of this Statement is to address those and other accounting and financial reporting implications that result from the replacement of an IBOR.
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Statement No. GASB 94 **Public-Private and Public-Public Partnerships and Availability Payment Arrangements** Under Review

Issue Date: March 2020 Effective for periods beginning after June 15, 2022

Description: The primary objective of this Statement is to improve financial reporting by addressing issues related to public-private and public-public partnership arrangements (PPPs). As used in this Statement, a PPP is an arrangement in which a government (the transferor) contracts with an operator (a governmental or nongovernmental entity) to provide public services by conveying control of the right to operate or use a nonfinancial asset, such as infrastructure or other capital asset (the underlying PPP asset), for a period of time in an exchange or exchange-like transaction. Some PPPs meet the definition of a service concession arrangement (SCA), which the Board defines in this Statement as a PPP in which (1) the operator collects and is compensated by fees from third parties; (2) the transferor determines or has the ability to modify or approve which services the operator is required to provide, to whom the operator is required to provide the services, and the prices or rates that can be charged for the services; and (3) the transferor is entitled to significant residual interest in the service utility of the underlying PPP asset at the end of the arrangement.

This Statement also provides guidance for accounting and financial reporting for availability payment arrangements (APAs). As defined in this Statement, an APA is an arrangement in which a government compensates an operator for services that may include designing, constructing, financing, maintaining, or operating an underlying nonfinancial asset for a period of time in an exchange or exchange-like transaction.

Statement No. GASB 96 **Subscription-Based Information Technology Arrangements** Under Review

Issue Date: May 2020 Effective for periods beginning after June 15, 2022

Description: This Statement provides guidance on the accounting and financial reporting for subscription-based information technology arrangements (SBITAs) for government end users (governments). This Statement (1) defines a SBITA; (2) establishes that a SBITA results in a right-to-use subscription asset—an intangible asset—and a corresponding subscription liability; (3) provides the capitalization criteria for outlays other than subscription payments, including implementation costs of a SBITA; and (4) requires note disclosures regarding a SBITA. To the extent relevant, the standards for SBITAs are based on the standards established in Statement No. 87, Leases, as amended.

Statement No. GASB 97 **Certain Component Unit Criteria, and Accounting and Financial Reporting for Internal Revenue Code Section 457 Deferred Compensation Plans – an amendment of GASB Statements No. 14 and No. 84, and a supersession of GASB Statement No. 32** Under Review

Issue Date: June 2020 Effective for periods beginning after June 15, 2021

Description: The primary objectives of this Statement are to (1) increase consistency and comparability related to the reporting of fiduciary component units in circumstances in which a potential component unit does not have a governing board and the primary government performs the duties that a governing board typically would perform; (2) mitigate costs associated with the reporting of certain defined contribution pension plans, defined contribution other postemployment benefit (OPEB) plans, and employee benefit plans other than pension plans or OPEB plans (other employee benefit plans) as fiduciary component units in fiduciary fund financial statements; and (3) enhance the relevance, consistency, and comparability of the accounting and financial reporting for Internal Revenue Code (IRC) Section 457 deferred compensation plans (Section 457 plans) that meet the definition of a pension plan and for benefits provided through those plans.

This Statement requires that for purposes of determining whether a primary government is financially accountable for a potential component unit, except for a potential component unit that is a defined contribution pension plan, a defined contribution OPEB plan, or an other employee benefit plan (for example, certain Section 457 plans), the absence of a governing board should be treated the same as the appointment of a voting majority of a governing board if the primary government performs the duties that a governing board typically would perform.

This Statement also requires that the financial burden criterion in paragraph 7 of Statement No. 84, Fiduciary Activities, be applicable to only defined benefit pension plans and defined benefit OPEB plans that are administered through trusts that meet the criteria in paragraph 3 of Statement No. 67, Financial Reporting for Pension Plans, or paragraph 3 of Statement No. 74, Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans, respectively.

This Statement (1) requires that a Section 457 plan be classified as either a pension plan or another employee benefit plan depending on whether the plan meets the definition of a pension plan and (2) clarifies that Statement 84, as amended, should be applied to all arrangements organized under IRC Section 457 to determine whether those arrangements should be reported as fiduciary activities.

Note 2 – Costs to be Recovered From Future Revenue (CTBR)

The Authority's rates are established based upon debt service and operating fund requirements. Depreciation is not considered in the cost of service calculation used to design rates. In accordance with GASB 62, the differences between debt principal maturities (adjusted for the effects of premiums, discounts, expenses and amortization of deferred gains and losses) and depreciation on debt financed assets are recognized as CTBR. The recovery of outstanding amounts recorded as CTBR will coincide with the repayment of the applicable outstanding debt. The Authority's summary of CTBR activity is recapped below:

Years Ended December 31,	**2021**	2020[1]
	(Millions)	
CTBR regulatory asset:		
Balance	**$ 222.9**	$ 219.8
CTBR expense/(reduction to expense):		
Net expense	**$ (3.1)**	$ 54.4

[1] A true-up was made in 2020 to revise a prior year CTBR depreciation rate resulting in an entry to decrease the CTBR asset $58.1 million and increase the CTBR expense the same amount.

Note 3 – Capital Assets

Capital asset activity for the years ended December 31, 2021 and 2020 was as follows:

	Beginning Balances	**Increases**	**Decreases**	**Ending Balances**
		Year 2021 (Thousands)		
Utility plant	**$ 8,572,695**	**$ 304,784**	**$ (76,745)**	**$ 8,800,734**
Long lived assets-asset retirement cost	**269,662**	**0**	**(2,681)**	**266,981**
Accumulated depreciation	**(4,252,077)**	**(263,346)**	**93,351**	**(4,422,072)**
Total utility plant-net	**4,590,280**	**41,438**	**13,925**	**4,645,643**
Construction work in progress	**447,309**	**188,546**	**(304,790)**	**331,065**
Other physical property-net	**27,636**	**1,992**	**(3,136)**	**26,492**
Totals	**$ 5,065,225**	**$ 231,976**	**$ (294,001)**	**$ 5,003,200**

	Beginning Balances	Increases	Decreases	Ending Balances
		Year 2020 (Thousands)		
Utility plant	$ 8,380,775	$ 225,541	$ (33,621)	$ 8,572,695
Long lived assets-asset retirement cost	265,116	4,546	0	269,662
Accumulated depreciation	(4,055,811)	(248,736)	52,470	(4,252,077)
Total utility plant-net	4,590,080	(18,649)	18,849	4,590,280
Construction work in progress	502,651	175,726	(231,068)	447,309
Other physical property-net	27,662	214	(240)	27,636
Totals	$ 5,120,393	$ 157,291	$ (212,459)	$ 5,065,225

Note 4 – Cash and Investments Held by Trustee and Fund Details

All cash and investments of the Authority are held and maintained by custodians and trustees. The use of unexpended proceeds from sale of bonds, debt service funds and other sources is designated in accordance with applicable provisions of various bond resolutions, the Enabling Act included in the South Carolina Code of Laws (the "Enabling Act") or by management directive. Restricted funds have constraints placed on their use (see Note 1 - D – "Restricted Assets"). The use of unrestricted funds may be either designated for a specific use by management directive or undesignated but are available to provide liquidity for operations as needed.

Following are the details of the Authority's funds which are classified in the accompanying financial statements as unrestricted and restricted cash, cash equivalents and investments:

Years Ended December 31,	**2021**			2020		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 68,412**	**$ 34,544**	**$ 102,956**	$ 82,571	$ 41,283	$ 123,854
Debt Reduction	**6,123**	**89,490**	**95,613**	4,215	-	4,215
Funds from Taxable Borrowings	**15,655**	**-**	**15,655**	2,691	-	2,691
General Improvement	**9**	**-**	**9**	11	-	11
Internal Nuclear Decommissioning Fund	**268**	**92,144**	**92,412**	311	91,636	91,947
Nuclear Fuel	**9,408**	**4,000**	**13,408**	1,475	4,003	5,478
Revenue and Operating	**135,544**	**4,248**	**139,792**	110,096	-	110,096
Contingency / Sub-Revenue	**39,817**	**30,160**	**69,977**	25,015	9,997	35,012
Special Reserve	**24,251**	**49,039**	**73,290**	26,397	42,292	68,689
Total	**$ 299,487**	**$ 303,625**	**$ 603,112**	$ 252,782	$ 189,211	$ 441,993
Current Restricted:						
Debt Service Funds	**15,009**	**32,529**	**47,538**	20,161	29,865	50,026
Funds from Tax-exempt Borrowings	**18,721**	**127,504**	**146,225**	35,315	69,154	104,469
Special Reserve and Other	**2,900**	**22,310**	**25,210**	3,024	14,753	17,777
Total	**$ 36,630**	**$ 182,343**	**$ 218,973**	$ 58,500	$ 113,772	$ 172,272
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 269**	**$ 152,254**	**$ 152,523**	$ 803	$ 154,077	$ 154,880
Total	**$ 269**	**$ 152,254**	**$ 152,523**	$ 803	$ 154,077	$ 154,880
TOTAL FUNDS	**$ 336,386**	**$ 638,222**	**$ 974,608**	$ 312,085	$ 457,060	$ 769,145

Cash and investments as of December 31, consisted of the following:	2021	2020
Cash/Deposits	**$ 88,312**	$ 83,037
Investments	**886,296**	686,108
Total cash and investments	**$ 974,608**	$ 769,145

Current Unrestricted Funds - These funds are used for operating activities for the Authority's respective systems. Although funds are segregated per management directive based on their intended use, since no restrictions apply, the funds are available to provide additional liquidity for operations. Included in this category is the internal Nuclear Decommissioning Fund intended by management to be used to offset future nuclear decommissioning costs and represents amounts in excess of the mandated Nuclear Regulatory Commission ("NRC") decommissioning requirement which is funded and separately held in an external Nuclear Decommissioning Trust. Also included are funds from taxable borrowings intended to be used for both capital construction costs and for working capital purposes, as expected at the time proceeds are borrowed.

Current Restricted Funds - These funds are restricted in their allowed use. Debt service funds are restricted for payment of principal and interest debt service on outstanding debt. Funds from tax-exempt borrowings are intended to be used for capital construction costs as expected at the time proceeds are borrowed and are restricted pursuant to sections of both the U.S. Treasury Regulations and the Internal Revenue Code that govern the use of tax-exempt debt. Other funds are restricted for other special purposes.

Noncurrent Restricted Funds - These funds are restricted as to their specific use. The external Nuclear Decommissioning Trust is restricted for future nuclear decommissioning costs and represents the mandated NRC funding requirements.

The Authority's investments are authorized by the Enabling Act, the Authority's investment policy and the Revenue Obligation Resolution. Authorized investment types include Federal Agency Securities, State of South Carolina General Obligation Bonds and U.S. Treasury Obligations, all of which are limited to a 10-year maximum maturity in all portfolios, except the decommissioning funds. Certificates of Deposit and Repurchase Agreements are also authorized with a maximum maturity of one year.

Investments are recorded at fair value in accordance with GASB Statement No. 72, *Fair Value Measurement and Application*. Accordingly, the gains and losses in fair value are reflected as a component of non-operating income in the Statements of Revenues, Expenses and Changes in Net Position.

The Authority's investment activity in all fund categories is summarized as follows:

Years Ended December 31,	**2021**	2020
Total Portfolio	(Billions)	
Total investments	**$ 0.9**	$ 0.7
Purchases	**28.2**	20.6
Sales	**28.0**	20.6
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	**$ 244.7**	$ 246.0
Purchases	**185.3**	340.6
Sales	**177.8**	340.6
Unrealized holding gain/(loss)	**(8.8)**	9.8
Repurchase Agreements[1]	(Millions)	
Balance at December 31	**$ 100.0**	$ 100.0

[1] Securities underlying repurchase agreements must have a market value of at least 102 percent of the cost of the repurchase agreement and are delivered by broker/dealers to the Authority's custodial agents.

Common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk and foreign currency risk are as follows:

Risk Type	Exposure
Credit Risk - Risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. Measured by the assignment of rating by a nationally recognized statistical rating organization.	As of December 31, 2021 and 2020, all of the agency securities held by the Authority were rated AAA by Fitch Ratings, Aaa by Moody's Investors Service, Inc. and AA+ by Standard & Poor's Rating Services.
Custodial Credit Risk-Investments - Risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party.	As of December 31, 2021 and 2020, all of the Authority's investment securities are held by the Trustee or Agent of the Authority and therefore, there is no custodial risk for investment securities.
Custodial Credit Risk-Deposits - Risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party.	At December 31, 2021 and 2020, the Authority had no exposure to custodial credit risk for deposits that were uninsured and/or collateral that was held by the bank's agent not in the Authority's name.
Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer.	Investments in any one issuer (other than U. S. Treasury securities) that represent five percent or more of total Authority investments at December 31, 2021 and 2020 were as follows:

Security Type / Issuer	Fair Value	
	2021	2020
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 119,766**	$ 113,353
Federal National Mortgage Association	**Less than 5%**	32,143
Federal Farm Credit Bank	**278,431**	160,425
Federal Home Loan Mortgage Corp	**Less than 5%**	Less than 5%

Interest Rate Risk - Risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates.

The Authority manages its exposure to interest rate risk by investing in securities that mature as necessary to provide the cash flow and liquidity needed for operations. The following table shows the distribution of the Authority's investments by maturity as of December 31, 2021 and 2020:

		Investment Maturities as of December 31, 2021			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
		(Thousands)			
Collateralized Deposits	**$ 146,324**	**$ 146,074**	**$ 250**	**$ 0**	**$ 0**
Repurchase Agreements	**100,000**	**100,000**	**0**	**0**	**0**
Federal Agency Discount Notes	**104,432**	**104,432**	**0**	**0**	**0**
Federal Agency Securities	**347,174**	**97,576**	**65,241**	**70,697**	**113,660**
US Treasury Bills, Notes and Strips	**188,366**	**137,948**	**26,079**	**7,951**	**16,388**
	$ 886,268	**$ 586,030**	**$ 91,570**	**$ 78,648**	**$ 130,048**

		Investment Maturities as of December 31, 2020			
Security Type	Fair Value	Less than 1 Year	1 - 5	6 - 10	More than 10 Years
		(Thousands)			
Collateralized Deposits	$ 106,049	$ 106,049	$ 0	$ 0	$ 0
Repurchase Agreements	100,000	100,000	0	0	0
Federal Agency Discount Notes	46,368	44,369	1,999	0	0
Federal Agency Securities	299,454	38,811	64,544	25,932	170,167
US Treasury Bills, Notes and Strips	134,237	106,671	2,048	0	25,518
	$ 686,108	$ 395,900	$ 68,591	$ 25,932	$ 195,685

The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the external Nuclear Decommissioning Trust and internal Nuclear Decommissioning Fund. Together these accounts hold $31.0 million par in U.S. Treasury Strips ranging in maturity from August 15, 2029 to May 15, 2039. The accounts also hold $17.2 million par in government agency zero coupon securities in the two portfolios ranging in maturity from January 15, 2021 to April 15, 2030. Zero coupon bonds or U.S. Treasury Strips are subject to wider swings in their market value than coupon bonds. These portfolios are structured to hold these securities to maturity or early redemption. The Authority has a buy and hold strategy for these. Based on the Authority's current decommissioning assumptions, it is anticipated that no funds will be needed prior to 2042. The Authority has no other investments that are highly sensitive to interest rate fluctuations.

Foreign Currency Risk - Risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value.	The Authority is not authorized to invest in foreign currency and therefore has no exposure.
Fair Value of Investments	The Authority measures and records its investments using fair value measurement guidelines established by GAAP. These guidelines recognize a three-tiered fair value hierarchy, as follows:

Level 1: Quoted prices for identical investments in active markets;
Level 2: Observable inputs other than quoted market prices; and,
Level 3: Unobservable inputs.

The Authority had the following recurring fair value measurements as of December 31, 2021 and 2020:

2021	**Total**	**Level 1**	**Level 2**	**Level 3**
		(Thousands)		
Collateralized Deposits	**$ 146,324**	**$ 0**	**$ 146,324**	**$ 0**
Repurchase Agreements	**100,000**	**0**	**100,000**	**0**
Federal Agency Discount Notes	**104,432**	**0**	**104,432**	**0**
Federal Agency Securities	**347,174**	**0**	**347,174**	**0**
US Treasury Bills, Notes and Strips	**188,366**	**0**	**188,366**	**0**
	$ 886,296	**$ 0**	**$ 886,296**	**$ 0**

2020	Total	Level 1	Level 2	Level 3
		(Thousands)		
Collateralized Deposits	$ 106,049	$ 0	$106,049	$ 0
Repurchase Agreements	100,000	0	100,000	0
Federal Agency Discount Notes	46,368	0	46,368	0
Federal Agency Securities	299,454	0	299,454	0
US Treasury Bills, Notes and Strips	134,237	0	134,237	0
	$ 686,108	$ 0	$686,108	$ 0

Collateralized Deposit and Repurchase Agreements classified in Level 2 are valued using pricing based on the securities' relationship to benchmark quoted prices.

Fiduciary Funds – Prior to 2010, the Authority used the unfunded pay-as-you-go option (or cash disbursement) method pursuant to GASB 45 to record the net OPEB obligations. During 2010, the Authority elected to adopt an advanced or pre-funding policy and established an irrevocable trust with Synovus Trust Company. In 2018 with the implementation of GASB 75, the Authority established a formal funding plan and elected to fund the OPEB obligation over a 30-year closed period. This method of funding will result in a lower OPEB liability and establishes a method of writing off the regulatory asset as funding occurs.

For the OPEB Trust, the common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk and foreign currency risk are as follows:

Risk Type	Exposure
Credit Risk - Risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. Measured by the assignment of rating by a nationally recognized statistical rating organization.	As of December 31, 2021 and 2020, all of the agency securities held by the OPEB Trust were rated AAA by Fitch Ratings, Aaa by Moody's Investors Service, Inc. and AA+ by Standard & Poor's Rating Services.
Custodial Credit Risk-Investments - Risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party.	As of December 31, 2021 and 2020, all of the OPEB Trust's investment securities are held by the Trustee or Agent of the OPEB Trust and therefore, there is no custodial risk for investment securities.
Custodial Credit Risk-Deposits - Risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party.	At December 31, 2021 and 2020, the OPEB Trust had no exposure to custodial credit risk for deposits that were uninsured and/or collateral that was held by the bank's agent not in the Authority's name.
Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer.	Investments in any one issuer (other than U. S. Treasury securities) that represent five percent or more of total OPEB Trust investments at December 31, 2021 and 2020 were as follows:

Security Type / Issuer	**Fair Value**	
	2021	2020
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 23,122**	$ 22,933
Federal National Mortgage Association	**Less than 5%**	Less than 5%
Federal Farm Credit Bank	**38,359**	31,676
Federal Home Loan Mortgage Corp	**18,116**	17,483

Interest Rate Risk - Risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates.

The following table shows the distribution of the OPEB Trust's investments by maturity as of December 31, 2021 and 2020:

		Investment Maturities as of December 31, 2021			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
		(Thousands)			
Federal Agency Securities	**81,655**	**0**	**0**	**0**	**81,655**
Government Securities	**26,721**	**0**	**0**	**0**	**26,721**
	$ 108,376	**$ 0**	**$ 0**	**$ 0**	**$ 108,376**

		Investment Maturities as of December 31, 2020			
Security Type	Fair Value	Less than 1 Year	1 - 5	6 - 10	More than 10 Years
		(Thousands)			
Federal Agency Securities	74,299	0	0	0	74,299
Government Securities	28,601	0	0	0	28,601
	$ 102,900	$ 0	$ 0	$ 0	$ 102,900

Risk Type	Exposure
Foreign Currency Risk - Risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value.	The OPEB Trust is not authorized to invest in foreign currency and therefore has no exposure.

Fair Value of Investments

The Authority measures and records its investments using fair value measurement guidelines established by GAAP. These guidelines recognize a three-tiered fair value hierarchy, as follows:

Level 1: Quoted prices for identical investments in active markets;
Level 2: Observable inputs other than quoted market prices; and,
Level 3: Unobservable inputs.

The OPEB Trust had the following recurring fair value measurements as of December 31, 2021 and 2020:

		Level		
2021	**Total**	**1**	**2**	**3**
		(Thousands)		
Federal Agency Securities	**81,655**	**0**	**81,655**	**0**
Government Securities	**26,721**	**0**	**26,721**	**0**
	$ 108,376	**$ 0**	**$ 108,376**	**$ 0**

		Level		
2020	Total	1	2	3
		(Thousands)		
Federal Agency Securities	74,299	0	74,299	0
Government Securities	28,601	0	28,601	0
	$ 102,900	$ 0	$102,900	$ 0

Note 5 – Long -Term Debt

Debt Outstanding

The Authority's long-term debt at December 31, 2021 and 2020 consisted of the following:

	2021	2020	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2056)				
2009 Tax-exempt Refunding Series A	**$ 0**	$ 1,405	4.00-5.00	100
2009 Taxable Series C	**1,830**	2,070	6.224	P&I Plus Make-Whole Premium
2009 Taxable Series F	**100,000**	100,000	5.74	P&I Plus Make-Whole Premium
2010 Series C (Build America Bonds) (3)	**360,000**	360,000	6.454	P&I Plus Make-Whole Premium
2011 Refunding Series C	**0**	135,855	4.375-5.00	100
2012 Refunding Series A	**0**	39,355	3.00-5.00	100
2012 Taxable Series E	**230,460**	230,460	3.572-4.551	P&I Plus Make-Whole Premium
2013 Tax-exempt Series A	**152,655**	152,655	5.00-5.50	100
2013 Tax-exempt Refunding Series B	**388,730**	388,730	5.00-5.125	100
2013 Taxable Series C	**250,000**	250,000	5.784	P&I Plus Make-Whole Premium
2013 Tax-exempt Series E	**506,765**	506,765	5.00-5.50	100
2014 Tax-exempt Series A	**525,000**	525,000	5.00-5.50	100
2014 Tax-exempt Refunding Series B	**42,275**	42,275	5.00	100
2014 Tax-exempt Refunding Series C	**628,260**	646,605	3.00-5.50	100
2014 Taxable Refunding Series D	**31,795**	31,795	2.906-3.606	P&I Plus Make-Whole Premium
2015 Tax-exempt Refunding Series A	**558,925**	558,925	3.00-5.00	100
2015 Tax-exempt Refunding Series B	**64,870**	64,870	5.00	Non-callable
2015 Tax-exempt Refunding Series C	**19,940**	94,535	5.00	Non-callable
2015 Taxable Series D	**169,657**	169,657	4.77	P&I Plus Make-Whole Premium
2015 Tax-exempt Series E	**300,000**	300,000	5.25	100
2016 Tax-exempt Refunding Series A	**465,210**	471,015	3.125-5.00	100
2016 Tax-exempt Refunding Series B	**408,705**	408,705	2.75-5.25	100
2016 Tax-exempt Refunding Series C	**52,400**	52,400	3.00-5.00	100
2016 Taxable Series D	**174,980**	174,980	2.380	P&I Plus Make-Whole Premium
2019 Tax-exempt Refunding Series A[4]	**143,200**	162,885	Variable Rate	100
2020 Tax-exempt Refunding Series A	**337,145**	338,480	3.00-5.00	100
2020 Taxable Refunding Series B	**299,725**	299,725	1.485-2.659	P&I Plus Make-Whole Premium
2021 Tax-exempt Refunding Series A	**145,735**	0	4.00-5.00	100
2021 Tax-exempt Series B	**284,555**	0	4.00-5.00	100
Total Revenue Obligations	**6,642,817**	6,509,147		
Direct Placement Long-Term Revolving Credit Agreement: (matures through 2029)	**19,000**	110,000	N/A	N/A
Less: Current Portion - Long-term Debt	**107,791**	104,575		
Total Long-term Debt - (Net of current portion)	**$ 6,554,026**	$ 6,514,572		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2021.

(2) Call Price may only apply to certain maturities outstanding at December 31, 2021.

(3) These bonds were issued as "Build America Bonds" under the American Recovery and Reinvestment Act of 2009 and are eligible to receive an interest subsidy payment from the United States Department of Treasury in an amount up to 35% of interest payable on the bonds.

(4) Interest is based on a weekly rate.

Changes in Long-Term Debt

Long-term debt (LTD) activity for the years ended December 31, 2021 and 2020 was as follows:

	Gross LTD Beginning Balances	Increases	Decreases	Gross LTD Ending Balance	Current Portion LTD	Total LTD (Net of Current Portion)	Unamortized Debt Discounts and Premiums	LTD-Net Ending Balances
				YEAR 2021 (Thousands)				
Revenue Obligations	**$ 6,509,147**	**$ 430,290**	**$ (296,620)**	**$ 6,642,817**	**$ 107,791**	**$ 6,535,026**	**$ 407,565**	**$ 6,942,591**
Direct Placement Long-Term Revolving Credit Agreement	**136,100**	**0**	**(113,889)**	**22,211**	**3,211**	**19,000**	**0**	**19,000**
Totals	**$ 6,645,247**	**$ 430,290**	**$ (410,509)**	**$ 6,665,028**	**$ 111,002**	**$ 6,554,026**	**$ 407,565**	**$ 6,961,591**
				YEAR 2020 (Thousands)				
Revenue Obligations	$ 6,587,097	$ 638,205	$ (716,155)	$ 6,509,147	$ 104,575	$ 6,404,572	$ 342,705	$ 6,747,277
Direct Placement Long-Term Revolving Credit Agreement	135,266	175,100	(174,266)	136,100	26,100	110,000	0	110,000
Totals	$ 6,722,363	$ 813,305	$ (890,421)	$ 6,645,247	$ 130,675	$ 6,514,572	$ 342,705	$ 6,857,277

Summary of Long-Term Principal and Interest

Maturities and projected interest payments of long-term debt are as follows:

Year Ending December 31,	Revenue Obligations	Long-Term Revolving Credit Agreements	Total Principal	TOTAL Interest [1]	TOTAL
			(Thousands)		
2022	$ 107,791	$ 3,211	$ 111,002	$ 316,530	$ 427,532
2023	289,756	1,335	291,091	312,675	603,766
2024	118,471	11,335	129,806	303,432	433,238
2025	121,890	1,335	123,225	298,220	421,445
2026	143,622	1,335	144,957	292,639	437,596
2027-2031	832,775	3,660	836,435	1,367,302	2,203,737
2032-2036	995,200	0	995,200	1,176,625	2,171,825
2037-2041	924,007	0	924,007	942,675	1,866,682
2042-2046	1,145,810	0	1,145,810	704,472	1,850,282
2047-2051	1,140,235	0	1,140,235	395,685	1,535,920
2052-2056	823,260	0	823,260	102,092	925,352
Total	$ 6,642,817	$ 22,211	$ 6,665,028	$ 6,212,347	$ 12,877,375

[1] Does not reflect impact of subsidy interest payments on 2010 Taxable C (Build America Bonds). Years 2022-2036 include projected interest for Long-Term Revolving Credit Agreements and Variable Rate Debt.

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Summary of Refunded and Defeased Debt and Unamortized Losses

Refunded and defeased debt, original loss on refunding and the unamortized loss at December 31, 2021 are as follows:

Refunding Description	Refunded/Defeased (Thousands)	Debt	Outstanding	Original Loss (Thousands)	Unamortized Loss
Cash Defeasance	$ 20,000	1982 Series A	$ 0	$ 2,763	$ 37
Feb 2012 Defeasance	$ 5,615	2003 Refunding Series A	0	749	376
2013 Refunding Series B	$ 209,426	2003 Refunding Series A			
	7,070	2004 Series A			
	5,000	2006 Series A			
	6,565	2007 Series A			
	82,605	2008 Series B			
	1,125	2009 Series B			
	30,158	2011 Series A (LIBOR Index)			
	2,040	2012 Series D	0	14,446	9,987
2013 Refunding Series C	$ 35,584	2003 Refunding Series A			
	97,695	2008 Series B	0	4,601	2,810
2014 Refunding Series C &	$ 10,870	2003 Refunding Series A			
Taxable Refunding Series D	11,395	2005 Refunding Series A			
	419,105	2006 Series A			
	10,385	2006 Refunding Series C			
	175,775	2007 Series A			
	4,230	2007 Refunding Series B			
	15,000	2008 Series A			
	15,200	2009 Series B			
	12,920	2010 Refunding Series B			
	3,100	2011 Refunding Series B			
	5,625	2012 Refunding Series A			
	2,000	2012 Refunding Series B			
	15,185	2012 Refunding Series C			
	11,335	2012 Series D			
	18,185	2013 Taxable Series D (LIBOR Index)			
	44,075	Expansion Bond Refunding CP	0	32,936	20,022

Summary of Refunded and Defeased Debt and Unamortized Losses (continued)

Refunding Description	Refunded/Defeased (Thousands)	Debt	Outstanding	Original Loss (Thousands)	Unamortized Loss
2015 Refunding Series A	$ 13,370	2006 Series A			
	32,750	2007 Series A			
	93,035	2008 Series A			
	30,765	2009 Series B	$ 0	$ 21,487	$ 6,791
2015 Refunding Series B	$ 78,150	2005 Refunding Series C	0	4,987	1,126
2015 Refunding Series C	$ 87,560	2005 Refunding Series A			
	217,065	2005 Refunding Series B	0	24,366	291
2015 Series E	$ 100,000	Barclays Revolving Credit Agreement	0	89	75
2016 Refunding Series A	$ 75,885	2007 Series A			
	278,950	2008 Series A			
	20,905	2009 Refunding Series A			
	112,210	2009 Series B			
	75,000	2014 Series A (Step Coupon Bond)	0	56,068	33,475
2016 Refunding Series B	$ 97,715	2009 Series E	0	12,873	9,604
2019 Refunding Series A	$ 8,514	2004 Series M (1)			
	3,227	2005 Series M (1)			
	2,796	2006 Series M (1)			
	13,022	2008 Series M (1)			
	18,565	2010 Series M1(1)			
	16,401	2011 Series M2 (1)			
	14,084	2013 Series M1 (1)			
	28,773	2014 Series M1 (1)			
	20,453	2015 Series M1 (1)			
	25,407	2016 Series M1 (1)	0	1,747	633
2020 Refunding Series A	$ 5,510	2009 Series A	0	77	42
2021 CP Partial Redemption	$ 17,495	2019 Refunding Series A	0	846	795
2021 Refunding Series A	$ 135,855	2011 Refunding Series C			
	38,575	2012 Refunding Series A	0	344	334
Total			$ 0	$ 178,379	$ 86,398

(1) Includes Current Interest-Bearing Bonds (CIBS) and Capital Appreciation Bonds (CABS).

Summary of In-Substance Defeasance of Debt Using Only Existing Resources

Defeased debt, cash placed in escrow, and defeased debt outstanding at December 31, 2021 are as follows:

Description of Transaction		Defeased Debt	Cash Placed in Escrow	Defeased Debt Outstanding
			(Thousands)	
09/2018 Cash Defeasance	$	48,475 2009 Refunding Series A		
		37,305 2010 Refunding Series B		
		81,510 2011 Refunding Series B		
		8,015 2012 Refunding Series A		
		7,510 2012 Refunding Series C		
		6,325 2012 Series D		
		100,000 2013 Series A		
		7,920 2014 Refunding Series C		
		5,485 2015 Series A		
		43,690 2015 Refunding Series C	$ 107,269	$ 100,000
10/2019 Cash Defeasance	$	63,680 2009 Series C		
		2,285 2009 Series E		
		10,181 2010 Series M2 (1)		
		19,403 2011 Series M1 (1)		
		31,775 2012 Series D		
		32,370 2012 Series M1(1)		
		15,088 2012 Series M1 (1)		
		13,230 2012 Series M2 (1)		
		3,048 2013 Series M1 (1)		
		10,400 2015 Series M1 (1)		
		10,926 2016 Series M1 (1)		
		147,670 2016 Series D	$ 34,757	$ 31,775
Total			$ 142,026	$ 131,775

(1) Includes Current Interest-Bearing Bonds (CIBS) and Capital Appreciation Bonds (CABS).

Analysis of Prior Year Current Portion of Long-term Debt

As a part of its long-term capital structure plan, the Authority will be involved in a multi-year refinancing plan. As a result, each year certain maturities classified as current portion of long-term debt may be refinanced in the subsequent year prior to the maturity date.

Below is an analysis of the 2020 current portion of long-term debt showing the amounts paid as debt service in 2021.

Analysis of December 31, 2020 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from Revenues	$ 104,575
Total	$ 104,575

An analysis of the $89,285 current portion of long-term debt at December 31, 2019 showed that $89,285 was debt service paid from revenues.

Reconciliations of Interest Charges

Years Ended December 31,		**2021**		2020
		(Thousands)		
Reconciliation of interest cost to interest expense:				
Total interest cost	**$**	**313,177**	$	322,127
Interest charged to fuel expense		**(2)**		(396)
Interest charged to Camp Hall		**0**		(49)
Total interest expense on long-term debt	**$**	**313,175**	$	321,682
Reconciliation of interest cost to interest payments:				
Total interest cost	**$**	**313,177**	$	322,127
Accrued interest-current year		**(38,324)**		(37,919)
Accrued interest-prior year		**37,919**		40,401
Interest released by refundings		**(2,153)**		(10,270)
Accretion on capital appreciation minibonds		**0**		0
Total interest payments on long-term debt	**$**	**310,619**	$	314,339

Debt Service Coverage

Years Ended December 31,	2021	2020
	(Thousands)	
Operating revenues	**$ 1,765,785**	$ 1,627,427
Interest and investment revenue	**2,075**	3,216
Total revenues and income	**1,767,860**	1,630,643
Operating expenses	**(1,496,286)**	(1,263,683)
Depreciation	**259,075**	244,992
Total expenses	**(1,237,211)**	(1,018,691)
Funds available for debt service prior to distribution to the State	**530,649**	611,952
Distribution to the State	**(17,135)**	(17,479)
Funds available for debt service after distribution to the State	**$ 513,514**	$ 594,473
Debt Service on Accrual Basis:		
Principal on long-term debt	**$ 101,786**	$ 97,296
Interest on long-term debt	**313,175**	321,793
Long-term debt service paid from Revenues	**414,961**	419,089
Commercial paper and other principal and interest	**8,584**	35,183
Total debt service paid from Revenues	**$ 423,545**	$ 454,272
Debt Service Coverage Ratio:		
Excluding commercial paper and other:		
Prior to distribution to the State	**1.27**	1.46
After distribution to the State	**1.23**	1.41
Including commercial paper and other:		
Prior to distribution to the State	**1.25**	1.34
After distribution to the State	**1.21**	1.30

Fair Value of Debt Outstanding

The fair value of the Authority's debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the Authority for debt with the same remaining maturities. Based on the borrowing rates currently available to the Authority for debt with similar terms and average maturities, the fair value of debt was $7.7 billion and $7.7 billion at December 31, 2021 and 2020, respectively.

Bond Market Transactions

Bond market transactions for the year ended December 31, 2021 were as follows:

Revenue Obligations,
2021 Tax-Exempt Refunding Series A **Par** **Date**
and Tax-Exempt Improvement Series B **Amount: $430,290,000** **Authorized: August 26, 2021**
Summary: - Issued on September 2, 2021 at an all-in true interest rate of 2.719 percent
- Matures December 1, 2051

Bond market transactions for the year ended December 31, 2020 were as follows:

Revenue Obligations,
2020 Tax-Exempt Refunding and Imp. Par Date
Series A and Taxable Refunding Series B Amount: $638,205,000 Authorized: October 28,2020
Summary: - Issued on November 5, 2020 at an all-in true interest rate of 2.866 percent
- Matures December 1, 2043

Debt Covenant Compliance

As of December 31, 2021 and 2020, management believes the Authority was in compliance with all debt covenants. The Authority's bond indentures provide for certain restrictions, the most significant of which are:

(1) the Authority covenants to establish rates sufficient to pay all debt service, required lease payments, capital improvement fund requirements and all costs of operation and maintenance of the Authority's Electric and Water Systems and all necessary repairs, replacements and renewals thereof; and
(2) the Authority is restricted from issuing additional parity bonds unless certain conditions are met.

All Authority debt (Electric and Water Systems) issued pursuant to the Revenue Obligation Resolution is payable solely from and secured by a lien upon and pledge of the applicable Electric and Water Revenues of the Authority. Revenue Obligations are senior to:

(1) payment of expenses for operating and maintaining the Systems;
(2) payments for debt service on commercial paper;
(3) payments made into the Capital Improvement Fund.

As of December 31,	**2021**	2020
Outstanding Revenue Obligations	**$ 6.6 Billion**	$ 6.5 Billion
Estimated remaining interest payments	**$ 6.2 Billion**	$ 6.3 Billion
Issuance years (inclusive)	**2009 through 2021**	2009 through 2020
Maturity years (inclusive)	**2022 through 2056**	2021 through 2056

Note: Proceeds from these bonds were/will be used to fund a portion of the Authority's ongoing capital program or retire or refund certain outstanding debt of the Authority.

The Authority has outstanding indebtedness subject to the terms of its Master Revenue Obligation Resolution dated April 26, 1999 (Master Resolution), which contains a provision permitting the acceleration of all principal and interest on revenue obligations should there be an Event of Default.

Note 6 – Variable Rate Debt

The Board has authorized the issuance of variable rate debt not to exceed 20 percent of the aggregate Authority debt outstanding (including commercial paper) as of the last day of the most recent fiscal year for which audited financial statements of the Authority are available. At December 31, 2021, 4.0% of the Authority's aggregate debt outstanding was variable rate. The lien and pledge of Revenues securing variable rate debt issued as Revenue Obligations is senior to that securing commercial paper.

Commercial paper is issued for valid corporate purposes with a term not to exceed 120 days. The information related to commercial paper was as follows:

Years Ended December 31,		**2021**		2020
Commercial paper outstanding (000's)	**$**	**120,832**	$	171,251
Effective interest rate (at December 31)		**.15%**		.21%
Average annual amount outstanding (000's)	**$**	**167,247**	$	151,625
Average maturity		**63 Days**		42 Days
Average annual effective interest rate		**.13%**		.84%

As of December 31, 2021, the Authority had secured Irrevocable Direct Pay Letters of Credit and Reimbursement Agreements with Barclays Bank PLC totaling $300.0 million. These agreements are used to support the Authority's issuance of up to $300.0 million of commercial paper. There were no loans under the agreements during 2021 or 2020. $120.8 million of commercial paper supported by the agreements has been issued and the unused available commercial paper capacity was $179.2 million as of December 31, 2021.

As of December 31, 2021, the Authority had a Revolving Credit Agreement with Bank of America, N.A. for $200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on September 10, 2020 and amended on December 28, 2021 and expires on March 31, 2022. The unused available capacity was $200.0 million.

As of December 31, 2021, the Authority had a Revolving Credit Agreement with TD Bank, N.A. for $200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on July 27, 2017 and expires June 30, 2022. A total of $22.2 million of loans remain outstanding at December 31, 2021. The unused available capacity on this line was $177.8 million as of December 31, 2021.

As of December 31, 2021, the Authority had a Revolving Credit Agreement with J.P. Morgan Chase Bank, N.A. for $100.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on December 28, 2021 and expires December 27, 2024. The unused available capacity on this line was $100.0 million as of December 31, 2021.

The Authority also has debt outstanding under Revolving Credit Agreements (RCAs) and Reimbursement Agreements with the banks identified above. The RCAs contain provisions permitting, by written notice, the acceleration of outstanding debt and accrued interest upon the occurrence of an event of default and automatically accelerating debt outstanding under the RCAs without such notice upon the occurrence of an event of default relating to certain acts of bankruptcy or insolvency relating to the Authority. The RCAs also contain provisions permitting the applicable lender upon an event of default to terminate its agreement and refuse to advance further funds and providing that such termination of its agreement will automatically occur upon the occurrence of an Event of Default relating to certain acts of bankruptcy or insolvency relating to the Authority (unless such acceleration is waived by the lender where applicable). The Reimbursement Agreements similarly contain provisions permitting, by written notice, the acceleration of debt outstanding under the Agreements upon the occurrence of an event of default and automatically accelerating debt outstanding under the Agreements without such notice upon the occurrence of an event of default relating to certain acts of bankruptcy or insolvency relating to the Authority. Each Reimbursement Agreement also contains provisions that permit the Bank upon an event of default to deliver a Final Drawing Notice stating that an event of default has occurred under such Agreement, directing that no additional Series A/AA Notes or Series B/BB Notes, as applicable, be issued and stating that the Letter of Credit for the Series A/AA Notes or Series B/BB Notes, as applicable, will terminate on the earlier of (i) the tenth day following the delivery of such notice and (ii) the date on which the drawing on the applicable Letter of Credit resulting from the delivery of such Final Drawing Notice is honored by the Bank.

Note 7 – Summer Nuclear Station

Summer Nuclear Unit 1

The Authority and Dominion are parties to a joint ownership agreement providing that the Authority and Dominion shall own Unit 1 at the Summer Nuclear Station ("Summer Nuclear Unit 1") with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. Dominion is solely responsible for the design, construction, budgeting, management, operation, maintenance and decommissioning of Summer Nuclear Unit 1 and the Authority is obligated to pay its ownership share of all costs relating thereto. The Authority receives 33 1/3 percent of the net electricity generated. In 2004, the NRC granted a twenty-year extension to the operating license for Summer Nuclear Unit 1, extending it to August 6, 2042.

Authority's Share of Summer Nuclear - Unit 1

Years Ended December 31,		**2021**		2020
		(Millions)		
Plant balances before depreciation	**$**	**825.4**	$	734.7
Accumulated depreciation		**340.2**		354.3
Operation & maintenance expense		**80.2**		81.0

Nuclear fuel costs are being amortized based on energy expended using the unit-of-production method. This amortization is included in fuel expense and recovered through the Authority's rates.

Dominion contracted with HOLTEC International, The Shaw Group, Inc. and Westinghouse to build a licensed Independent Spent Fuel Storage Installation ("ISFSI"), which was completed and commenced receiving fuel in 2016. Because of the Department of Energy's ("DOE") failure to meet its obligation to dispose of spent fuel, Dominion and the Authority are being reimbursed by DOE for a portion of ISFSI project costs. The Authority expects this reimbursement will equal approximately 75 percent of total project costs.

The NRC requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2020 and the NRC's imposed minimum requirement. Based on these estimates and assuming a SAFSTOR (delayed) decommissioning and an eighty year plant life, the Authority's one-third share of the estimated decommissioning costs of Summer Nuclear Unit 1 equals approximately $439.5 million in 2021 dollars. As deposits are made, the Authority debits FERC account 532 – Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates.

Based on current decommissioning cost estimates, these funds, which total approximately $244.7 million (adjusted to market) at December 31, 2021, along with investment earnings, additional contributions, and credits from future DOE reimbursements for spent fuel storage, are estimated to provide enough funds for the Authority's one-third share of the total decommissioning cost for Summer Nuclear Unit 1.

Summer Nuclear Units 2 and 3

Events Relative to Summer Nuclear Units 2 and 3

In January of 2008, the Authority approved a generation resource plan that included the development of two new 1,117 MW nuclear generating units (individually, "Summer Nuclear Unit 2" and "Summer Nuclear Unit 3" and together, "Summer Nuclear Units 2 and 3") at the V.C. Summer Nuclear Generating Station. Summer Nuclear Units 2 and 3 would be jointly-owned by the Authority (45% ownership interest) and, at the time, SCE&G (now known as Dominion) (55% ownership interest) (together, the "Owners").

In May of 2008, SCE&G, acting for itself and as agent for the Authority, entered into the EPC Agreement, with a contractor consortium consisting of Westinghouse and Stone & Webster, Inc. ("Stone & Webster" and together with Westinghouse, the "Consortium"), a wholly-owned subsidiary of Shaw. Under the EPC Agreement, the Consortium would supply, construct, test and start up Summer Nuclear Units 2 and 3, with guaranteed substantial completion dates of April 2016 for Summer Nuclear Unit 2 and January 2019 for Summer Nuclear Unit 3. In addition, Westinghouse's indirect parent company, Toshiba Corporation ("Toshiba"), provided a guaranty of Westinghouse's payment obligations under the EPC Agreement (the "Guaranty") and Stone & Webster's parent company, Shaw, likewise provided a guaranty of Stone & Webster's payment obligations under the EPC Agreement.

The cost of Summer Nuclear Units 2 and 3 was originally estimated to be approximately $9.8 billion. Based on its 45% ownership interest, the Authority's portion of the cost to construct Summer Nuclear Units 2 and 3 was approximately $4.4 billion. The Authority's funding sources for Summer Nuclear Units 2 and 3 consisted of the proceeds of Revenue Obligations issued pursuant to the Revenue Obligation Resolution between 2008 and 2016 and outstanding in the aggregate principal amount of $3.630 and $3.634 million as of December 31, 2021 and 2020, respectively.

During the course of construction, issues materialized that affected the budget and schedule for Summer Nuclear Units 2 and 3. In February of 2017, Toshiba Corporation announced a $6.3 billion write-down on the value of Westinghouse, stemming from its two U.S. nuclear construction projects, Summer Nuclear Units 2 and 3 and Units 3 and 4 at the Vogtle nuclear power plant located in Burke County, Georgia ("Vogtle Nuclear Units 3 and 4"). A month later, Westinghouse and 29 affiliated companies filed a petition pursuant to Chapter 11 of the Bankruptcy Code (the "Petition") in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court").

After the filing of the Petition, the Owners, led by SCE&G, conducted a comprehensive analysis regarding the continued viability of Summer Nuclear Units 2 and 3. The analysis revealed that: (i) the costs to complete Summer Nuclear Units 2 and 3 (including labor costs) would be much higher than previously expected; and (ii) the construction schedule would take much longer than previously expected. In particular, (i) the Owners' analysis estimated that completion of Summer Nuclear Units 2 and 3 would be delayed until 2023 for Summer Nuclear Unit 2 and 2024 for Summer Nuclear Unit 3 and (ii) the new cost estimate for Summer Nuclear Units 2 and 3 was over $25 billion, placing the Authority's 45% share at $11.4 billion ($8 billion in construction costs and $3.4 billion in interest expense), an increase from the then-current projected cost of $6.2 billion.

The Owners also entered into negotiations with Toshiba for the purpose of acknowledging and defining Toshiba's obligations under the Guaranty and establishing a schedule for the full payment of such obligations to the Owners. As a result, in July of 2017, the Owners and Toshiba entered into a settlement agreement (the "Toshiba Settlement Agreement") which included, among other things Toshiba's agreement that it would pay the Guaranty obligation in the amount of $2.168 billion (the Authority's share (based on its 45% ownership interest) equaling $975.6 million)), in accordance with a payment schedule commencing in 2017 and continuing through 2022.

On July 31, 2017, the Authority approved the wind-down and suspension of construction of Summer Nuclear Units 2 and 3 and the preservation and protection of the site and related components and equipment. SCANA approved similar action on the same day. To date, the Authority had spent approximately $4.7 billion in construction and interest costs. Upon suspending construction, and in accordance with GASB 62, the Authority ceased capitalizing interest expense on the debt incurred to fund Summer Nuclear Units 2 and 3 as of July 31, 2017.

In early September of 2017, the Owners filed two proofs of claim in unliquidated amounts in connection with the Westinghouse bankruptcy proceeding. Later that month, the Owners and Citibank, N.A. ("Citibank") entered into an Assignment and Purchase Agreement (the "Assignment and Purchase Agreement"), pursuant to which the Owners sold and assigned rights to receive payment under the Toshiba Settlement Agreement and rights, duties and obligations arising under the two proofs of claim filed in the Westinghouse bankruptcy proceeding to Citibank, in exchange for a purchase price of $1,847,075,400 (the Authority's share (based on its 45% ownership interest) equaling $831,183,930). Excluded from the sale was the initial $150 million payment (the Authority's share (based on its 45% ownership interest) equaling $67.5 million) received by the Owners under the Toshiba Settlement Agreement.

In January of 2018, the Owners entered into Amendment No. 1 of the Toshiba Settlement Agreement and Amendment No. 1 of the Assignment and Purchase Agreement. These amendments had the effect of capping at $60 million the Owners' current obligation to reimburse Citibank for payments the Owners received from the Westinghouse estate that had the effect of reducing mechanics liens at the site of Summer Nuclear Units 2 and 3 (the Authority's share (based on its 45% ownership interest) equaling $27.0 million). To date, the Owners have not made any reimbursement payments to Citibank.

Also, in January, the State's Department of Revenue ("DOR") notified SCE&G that the sales and use tax returns for Summer Nuclear Units 2 and 3 had been assigned for a sales and use tax audit. During a meeting in February, the DOR took the position that, because Summer Nuclear Units 2 and 3 had been abandoned and the facility was not completed and would not produce electricity, the materials for Summer Nuclear Units 2 and 3 were not tax-exempt and sales tax payments were due on previously tax-exempt purchases. In May, the DOR issued a proposed notice of assessment in the amount of $421 million. The Authority has submitted a protest to the notice of proposed assessment and continues to dispute the position that sales taxes are due and owing. Pursuant to an agreement between the Authority and Dominion ancillary to the Cook Settlement, Dominion agreed to hold the Authority harmless for any potential liability associated with the Department of Revenue Matter.

In March of 2018, the Bankruptcy Court issued its order confirming Westinghouse's Chapter 11 plan of reorganization (the "Westinghouse Plan of Reorganization"). The Westinghouse Plan of Reorganization provided for the sale of Westinghouse to Brookfield Business Partners, L.P. ("Brookfield") for $4.6 billion, which occurred in August of 2018.

The Westinghouse Plan of Reorganization also provided for the payment of claims made by allowed general unsecured creditors in an amount equal to the lesser of: (i) their pro rata share of certain funds; or (ii) 100% of the amount of the allowed claim. Under the Westinghouse Plan of Reorganization, creditors providing materials and services at the site of Summer Nuclear Units 2 and 3 were classified as Class 3A General Unsecured Creditors. In December of 2018, an initial distribution was made on behalf of the Westinghouse estate to Class 3A General Unsecured Creditors equaling approximately 25% of the allowed amount of each claim. Subsequently, a catch-up payment was made representing 75% of the allowed amount of each claim. Representatives of W. Wind Down Company, LLC, the entity responsible for paying the Westinghouse claims under the supervision of the Bankruptcy Court, has represented to the Owners that funds have been reserved to pay 100% of the presently disputed claims by the Class 3A General Unsecured Creditors. In the event that such disputed claims are not paid in full from the Westinghouse estate, the Class 3A General Unsecured Creditors could claim that the Authority is liable for payment under a mechanic's lien theory.

In June of 2018, SCE&G and the Authority signed a Right of Entry Agreement allowing the Authority to begin implementation of a Maintenance, Preservation, and Documentation (MPD) Program to preserve the equipment relative to Summer Nuclear Units 2 and 3 for sale. The Authority contracted with Fluor to perform an assessment of the condition of the equipment and to implement an MPD Program to help protect its value. Fluor began this scope of work in July of that year. The Authority has since approved an extension of the MPD Program through the end of 2020. The Authority has spent $15.8 million through December 2021 to preserve the equipment.

In January of 2019, SCANA and its subsidiaries, including SCE&G, merged with Dominion. Through the merger, SCANA became a wholly-owned subsidiary of Dominion.

On April 5, 2019, Westinghouse filed an adversary proceeding complaint in the United States Bankruptcy Court for the Southern District of New York against the Authority, claiming that it is the owner of and has title to certain equipment related to the construction of Summer Nuclear Units 2 and 3 pursuant to the EPC Agreement. The parties settled the matter on August 29, 2020.

Sale of Summer Nuclear Units 2 and 3 Assets

After suspending construction, the Authority sought additional project partners or financial support for Summer Nuclear Units 2 and 3. Finding none, the Authority looked to whether or not it could sell the fuel assets and non-fuel assets comprising Summer Nuclear Units 2 and 3 equipment and commodities. First, an evaluation was conducted in accordance with GASB 42 to determine whether the assets were impaired. With the exception of certain assets to be repurposed at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the assets were determined to be impaired because: (i) the decline in service utility of the assets was large in magnitude; (ii) the event or change in circumstance was outside the normal life cycle of the assets; and (iii) although Summer Nuclear Units 2 and 3 could be completed at some point in the future, the Authority had no near-term plans to do so. Next, the Authority set out to determine the fair value of the impaired assets.

Based on the results of a fair value determination of the assets, the write-off of the construction costs and fuel for Summer Nuclear Units 2 and 3 for the year ended December 31, 2017 totaled $4.211 billion. In January of 2018, the Authority approved the use of regulatory accounting for the $4.211 billion impairment write-off. The majority of Summer Nuclear Units 2 and 3 was financed with borrowed funds and for rate-making purposes, the Authority includes the debt service on these borrowed funds in its rates. Therefore, the impairment will be recorded as a regulatory asset and amortized through November 2056 to align with the principal payments on the associated indebtedness.

In December of 2017, the Authority approved the use of regulatory accounting to defer a portion of post-suspension capitalized interest. With the cessation of capitalized interest and the timing of the suspension, the Authority would be unable to collect a portion of the post-suspension capitalized interest in its rates. Such post-suspension capitalized interest totaled $37.1 million as of December 31, 2017 and, like the $4.211 billion impairment write-off, is recorded as a regulatory asset and amortized through November 2056 in order to align with the principal payments on the debt used to pay the interest.

In December of 2017, the Authority also approved the use of regulatory accounting to defer the recognition of income from the Toshiba Settlement Agreement. The Authority recorded a regulatory deferred inflow of $898.2 million with respect to the Toshiba Settlement Agreement as of December 31, 2017, to be amortized over time in order to align with the manner in which the settlement proceeds are used to reduce debt service payments.

In the event that the principal maturities of the indebtedness described above changed materially, the amortization will be adjusted to better align with the new maturities. As such, the $4.211 billion impairment write-off was adjusted to $3.697 billion as of December 31, 2021, to account for a decrease of $40.2 million for adjustments after year end 2017 and amortization of $473.8 million. The $898.2 million deferred inflow with respect to the Toshiba Settlement Agreement was similarly adjusted to $251.1 million to account for $13.8 million in interest income and amortization of $660.9 million.

The following table summarizes the nuclear-related regulatory items:

Regulatory Item	Classification	Original Amount	2018 - 2021 Amortization	2018 - 2021 Changes	2021 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($ 473.8 million)	($40.2 million)	$ 3.697 billion
Nuclear post-suspension interest	Asset	$ 37.1 million			$ 37.1 million
Toshiba Settlement Agreement	Deferred Inflow	$898.2 million	($ 660.9 million)	$ 13.8 million	$251.1 million

Switchyard Assets. SCE&G and the Authority determined that certain transmission-related switchyard assets that were part of Summer Nuclear Units 2 and 3 (the "Switchyard Assets") were unimpaired. During 2018, SCE&G (now Dominion) and the Authority agreed that the ownership interest in the Switchyard Assets needed to be adjusted and began negotiating an agreement to adjust the percentages and true-up the charges. In June of 2019, Dominion and the Authority entered into a Bill of Sale setting the amount of the true-up payment for the Switchyard Assets at $2,675,911. Dominion made this payment to the Authority in September 2019.

Forbearance Agreement. In December of 2018, SCE&G and the Authority executed a Forbearance Agreement (the "Forbearance Agreement") for the purpose of facilitating the possible domestic and international sales of equipment, commodities and plant components relative to Summer Nuclear Units 2 and 3. Pursuant to the Forbearance Agreement, SCE&G reaffirmed its irrevocable waiver of any and all rights in certain assets (the "Forbearance Assets") consisting of Summer Nuclear Units 2 and 3; ancillary facilities; intellectual property; equipment and materials on-site and off-site including, without limitation, assets, materials and equipment that are affixed to the real property at the site but are capable of being removed. Excluded from the Forbearance Assets were the underlying real property; certain specifically-identified assets excluded from the abandonment of Summer Nuclear Units 2 and 3 prior to December 31, 2017; substation and switchyard assets; the old New Nuclear Deployment (NND) building and nuclear fuel. Under the Forbearance Agreement, Dominion had thirty (30) days from the execution date to: (i) seek approval of the Forbearance Agreement from the PSC and (ii) take reasonable efforts to obtain the release of any security interest or mortgage attached to the Forbearance Assets. In March of 2019, (i) the PSC approved the Forbearance Agreement and (ii) Dominion provided the Authority with a fully-executed release.

Sales of Summer Nuclear Units 2 and 3 Assets. During calendar years 2018 - 2021, the Authority sold certain equipment and commodities to third parties. Through December 31, 2021, $35.8 million of materials have been sold.

In accordance with the settlement agreement reached between Westinghouse Electric Company, LLC ("WEC") and the Authority in August 2020 (the Westinghouse Settlement Agreement"), the Authority owns all of the non-nuclear equipment and proceeds from sales of nuclear-related equipment will be split between WEC and the Authority as provided in the Westinghouse Settlement Agreement as follows:

(1) Major non-installed nuclear equipment, 50% Authority and 50% WEC;
(2) Major installed nuclear equipment, 90% Authority and 10% WEC;
(3) Any other equipment that could be used in nuclear projects, 67% to the Authority and 33% to WEC.

In late 2020, the Authority entered into agreements with three outside entities to assist with the sale of surplus nuclear assets associated with Summer Nuclear Units 2 & 3. These assets are categorized as "subject" and "other" equipment, pursuant to the agreement with WEC. Following the first agreement, WEC will be solely responsible for marketing and sales of "subject" equipment. A second agreement was entered into with a large-scale utility, currently in the construction phase of two similar AP-1000 units. This agreement allows sales of "other" assets directly to the large-scale utility from the Authority. The third agreement is between the Authority and a global industrial sales company, specializing in investment recovery for surplus assets, to market and sell "other" equipment. Direct sales of "other" equipment to the large-scale utility are excluded from the agreement with the industrial sales company. In all three agreements, the Authority maintains approval privileges to all sales.

The Authority currently expects to use amounts received from the proceeds from the sale of nuclear-related equipment to pay down a portion of its outstanding debt.

Note 8 – Leases

Capital Lease

The Authority, as lessor, has a capital lease (the "Office Site Ground Lease Agreement") with Volvo Car USA, LLC, as lessee, covering a ground lease for an improved office site and associated acreage. The lease term is 20 years with annual payments of $404,167 due each January 1st, starting January 1, 2018. The sum of the minimum lease payments total $8.1 million and include site work of $5.9 million, land of $0.5 million and interest of $1.7 million (based on the 20-year Treasury Bill at the effective rate of 2.58%). Volvo Car USA, LLC has options to purchase the office site as follows:

1. At any time until the expiration of the capital lease term, Volvo Car USA, LLC shall have a purchase option, the price of which shall be determined as: (i) the amount sufficient to repay in full the land purchase price of $0.5 million; plus (ii) the costs and expenses incurred by the Authority for the site preparation of $5.9 million; plus (iii) interest added at 2.58% per annum; accruing from the work completion date through and until the date of payment by Volvo Car USA, LLC to Santee Cooper of the option purchase price; less (iv) the amount of rent paid by Volvo Car USA, LLC to the Authority as of the date of payment by Volvo Car USA, LLC of the option purchase price.
2. At expiration of the capital lease and if Volvo Car USA, LLC has paid all rent in accordance with the capital lease, Volvo Car USA, LLC shall have a purchase option with an option purchase price of $1.

Total minimum lease payments to be received from Volvo Car USA, LLC as of December 31, 2021 are as follows:

Year Ending December 31,	Minimum Lease Payments (Thousands)
2022	$ 404
2023	404
2024	404
2025	404
2026	404
Thereafter	4,446
Total	$ 6,466

Note 9 – Contracts with Electric Power Cooperatives

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 20 distribution cooperatives which are members of Central. Power supply and transmission services are provided to Central in accordance with a power system coordination and integration agreement (the Coordination Agreement). Under the Coordination Agreement, the Authority is the predominant supplier of energy needs for Central, excluding amounts supplied by Duke to the Upstate Load (Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative, Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc. and York Electric Cooperative, Inc.), energy Central receives from the Southeastern Power Administration (SEPA) and negligible amounts generated and purchased from others. In 2021, revenues pursuant to the Central Agreement were 58% of total sales of electricity, compared to 60% in 2020.

Central, under the terms of the Coordination Agreement, has the right to audit costs billed to them. Any differences found as a result of this process are accrued if they are probable and estimable. To the extent that differences arise, prospective adjustments are made to the cost of service and are reflected in operating revenues in the accompanying Statements of Revenues, Expenses and Changes in Net Position. In 2021, operating revenues were reduced by $21.5 million for 2016 - 2019 Central audit issues.

In 2013 the Central and Authority Boards approved an Amendment to the Coordination Agreement. As part of this Central agreed to extend their rights to terminate the agreement until December 31, 2058. The Coordination Agreement includes a 10-year rolling notice provision. For a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. The Coordination Agreement provides for closer cooperation on planning of future resources, gives Central the ability to "opt-out" of future generation resources, and provides for cost recovery of all resources completed or under construction as of the amendment effective date, including Summer Nuclear Units 2 and 3. The Authority and Central have resolved certain matters relating to the nuclear project through the execution of the Cook Settlement and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement.

Note 10 – Commitments and Contingencies

Budget - The Authority's 2022 three-year capital budget is as follows:

Years Ending December 31,	2022	2023	2024
		(Millions)	
Environmental Compliance [1]	$ 71.4	$ 68.9	$ 101.5
General System Improvements and Other [2]	241.2	236.9	245.0
Total Capital Budget [3]	$ 312.6	$ 305.8	$ 346.5

Budget Assumptions:

[1] Environmental Compliance is composed of project costs associated with ash pond closures and solid waste.

[2] Other includes Advanced Metering Infrastructure, FERC Relicensing, Camp Hall, and Renewables.

[3] Will be financed by internal funds or debt.

Purchase Commitments - The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2021. The disclosure of contract obligations shown below is based on the Authority's contract rates and represents management's best estimate of future expenditures under current long-term arrangements. Additional arrangements are expected to meet the Authority's full demand.

Years Ending December 31,		Total Volumes with Options [1]		Contract Volumes [2]
		(Thousands)		
2022	$	239,476	$	136,901
2023		198,975		96,100
2024		148,463		112,525
Total	$	586,914	$	345,526

[1] Includes tons which the Authority has the option to receive.
[2] Includes tons which the Authority must receive.

The Authority has the following outstanding obligations under existing long-term capacity and purchased power contracts as of December 31, 2021:

Contracts with Minimum Fixed Payment Obligations[1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	14 Years	$ 0

[1] The Armed Services Board of Contract Appeals has instructed Santee Cooper and the Corps of Engineers to negotiate capacity value, and the parties are working to determine same.

Contracts with Power Receipt and Payment Obligations [1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	4 Years	$ 61.9
2	2013	22 Years	455.6
1	2013	12 Years	5.4
1	2021	4 Years	22.4
1	2023	5 Years	24.1
1	2023	5 Years	25.9
1	2023	5 Years	14.3

[1] Payment required upon receipt of power. Assumes no change in indices or escalation.

The Authority purchases network integration transmission service through transmission agreements with Dominion, SOCO and Duke. This network transmission service is used to serve wholesale customers who are not in the Authority's direct-served territory; the Authority is obligated for costs associated with these transmission agreements. The table below shows the transmission obligations in 2022 and the total transmission obligations for 2023-2032. The wholesale customer obligations below represent projected transmission amounts through the term of the current contracts.

Transmission Obligations

		2022		2023-2032
		(Thousands)		
Other Customers	$	9,101	$	53,524
Total	$	9,101	$	53,524

As of December 31, 2020, Santee Cooper has executed four purchase power agreements with 5 year terms under the Public Utilities Regulatory Policies Act of 1978 (PURPA). A project associated with an agreement with Centerfield Solar, LLC, effective April 18, 2019, having a nameplate capacity of 75 MW, reached commercial operation in December 2020. An agreement with Alora Solar, LLC, was effective May 19, 2020, and the project is scheduled to achieve commercial operation in the 4th quarter of 2022 and has a nameplate capacity of approximately 75 MW. Projects totaling approximately 130 MW of nameplate capacity associated with agreements with Gunsight Solar, LLC, effective April 30, 2019, and Landrace Holdings, LLC, effective May 19, 2020, are expected to achieve commercial operation by the 4th quarter of 2023, respectively.

In 2020, Santee Cooper issued a Request for Proposals up to 500 MW of solar capacity and energy. To date, five contracts totaling 425 MW have been awarded with terms ranging from 15-20 years and expected commercial operation in 2023.

CSX Transportation, Inc. ("CSX") provides substantially all rail transportation service for the Authority's Cross and Winyah coal-fired generating stations. The Authority also interchanges with some short line railroads via CSX for the movement of coal as well. The CSX contract, effective January 1, 2011, and extended per amendment through June 30, 2025, effective July 1, 2020, continues to apply a price per ton of coal moved, along with a mileage-based fuel surcharge and minimum tonnage obligation.

The Authority has commitments for nuclear fuel, nuclear fuel conversion, enrichment and fabrication contracts for Summer Nuclear Units 1, 2 and 3. Nuclear fuel purchases for Units 2 and 3 ended once construction on the new units was suspended and remaining commitments now only apply to Unit 1. As of December 31, 2021, these contracts total approximately $78.1 million over the next 13 years.

On May 12, 2008, Dominion, for itself and as agent to the Authority, entered into a Uranium Hexafluoride ("UF6") Supply Agreement with Cameco, Inc. ("Cameco"), a Nevada corporation that supplies uranium products (the "Original Agreement"). The Original Agreement called for delivery of a total of 1,535,000 kilograms of elemental uranium ("kgU") of UF6 to Dominion. The total quantity to be delivered was spread out over the 2010 to 2016 time-period with an annual base quantity specified for each year. The Original Agreement was subsequently amended on January 25, 2011 (the "Amendment") (the Original Agreement, as amended by the Amendment, is hereinafter referred to as the "Agreement"), to provide for additional deliveries of UF6 over an extended contract term covering the period of 2017 to 2020. The Amendment called for an additional 1,640,000 kgU of UF6 to be delivered with 410,000 kgU identified as the annual base quantity for each year of the extended term. The Amendment also modified the pricing terms.

On December 18, 2018, Cameco initiated an arbitration proceeding alleging that Dominion was in breach of the Agreement when it did not take and pay for the full quantity of UF6 to be delivered under the Agreement, for use in Summer Nuclear Unit 1 and Summer Nuclear Units 2 and 3. In January 2021, the parties entered into a mutual release of claims and dismissed the arbitration.

Pursuant to the Settlement Agreement and Release dated March 17, 2020 between Dominion and the Authority, Dominion agreed to indemnify the Authority for any amounts required to satisfy a judgment or settlement in the Cameco arbitration.

The Authority successfully negotiated a Contractual Service Agreement with GEII, effective March 2016, that covers all units on the Rainey plant site. The Contractual Service Agreement provides unplanned maintenance coverage, rotor replacement and auxiliary parts replacement in addition to a Contract Performance Manager ("CPM"), initial spare parts, parts and services for specified planned maintenance outages, remote monitoring and diagnostics of the turbine generators and combustion tuning for the gas turbines. Based on the latest approved fuel forecast, the contract term extends through 2028 and the Authority's estimated remaining commitment on the contract is $48.5 million, including escalation.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation to supply gas transportation needs for its Rainey Generating Station. The service agreement is for 80,000 dekatherms per day of firm capacity and extends through November 1, 2031.

Byproducts- Coal combustion products ("CCP"), which include fly ash, bottom ash, and flue gas desulfurization products such as gypsum, are produced when coal is burned to generate electricity. The Authority has entered into contracts for the beneficial use of CCPs and continually looks for new markets and customers for the use of CCPs. The Authority supplies and delivers drywall quality gypsum to American Gypsum ("AG") in Georgetown, South Carolina under a long-term contract that includes minimum and maximum supply volumes. The gypsum is primarily sourced from synthetic gypsum produced at the Cross Generating Station ("CGS") and Winyah Generating Station ("WGS"). Currently and under projected dispatch assumptions, gypsum produced at CGS and WGS does not meet required minimum contract volumes, and shortfalls are obtained from several external sources of both natural and synthetic gypsum. Sources may vary based on availability and cost. Natural gypsum is currently purchased and delivered from International Materials Inc. Synthetic gypsum is currently purchased from Cameron Ag Products, LLC ("Cam Ag"). Cam Ag provides this source via rail from various sources in the Southeast to the Authority's Jefferies Station, from where it is delivered to AG. Additionally, ponded ash is reclaimed from the Authority's ash ponds for use in the cement and concrete industry. This pond ash is sold to multiple cement plants as a replacement for silica and alumina in their process. Dry fly ash is recovered directly from the operating units for use in the concrete industry, and bottom ash is beneficially used by concrete block manufacturers to produce concrete block. The Authority has multiple beneficial use agreements to facilitate beneficial use activities, one of which is the STAR Processed Fly Ash Operating and Sales Agreement between the Authority and The SEFA Group, Inc. ("SEFA"). Pursuant to this Agreement, the Authority supplies dry fly ash and/or ponded ash from the Winyah Station to SEFA who processes it in their staged turbulent air reactor ("STAR") unit to produce a high-quality fly ash which they market to the concrete industry. In addition, ponded gypsum, which does not meet wallboard specifications, is reclaimed from the Authority's slurry ponds for use in the agriculture and cement industries.

Risk Management - The Authority is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; business interruption; and errors and omissions. The Authority purchases commercial insurance to cover these risks, subject to coverage limits and various exclusions. Settled claims resulting from these risks did not exceed commercial insurance coverage in 2021. Policies are subject to deductibles ranging from $500 to $2.0 million, except for named storm losses which carry deductibles from $2.0 million up to $50.0 million. Also, a $1.4 million general liability self-insured layer exists between the Authority's primary and excess liability policies. During 2021, there were minimal payments made for general liability claims.

The Authority is self-insured for auto, worker's compensation and environmental incidents that do not arise out of an insured event. The Authority purchases commercial insurance, subject to coverage limits and various exclusions, to cover automotive exposure in excess of $2.0 million per incident. Estimated exposure for worker's compensation is based on an annual actuarial study using loss and exposure information valued as of June 30, 2021. In addition, there have been no third-party claims regarding environmental damages for 2021 or 2020.

Claim expenditures and liabilities are reported when it is probable that a loss has occurred, and the amount of the loss can be reasonably estimated. The amount of the self-insurance liabilities for auto, dental, worker's compensation and environmental remediation is based on the best estimate available. Changes in the reported liability were as follows:

Years Ended December 31,		**2021**		2020
		(Thousands)		
Unpaid claims and claim expense at beginning of year	**$**	**1,554**	$	2,690
Incurred claims and claim adjustment expenses:				
Add: Provision for current year events		**1,166**		576
Less: Payments for current and prior years		**1,131**		1,712
Total unpaid claims and claim expenses at end of year	**$**	**1,589**	$	1,554

The Authority pays insurance premiums to certain other State agencies to cover risks that may occur in normal operations. The insurers promise to pay to, or on behalf of, the insured for covered economic losses sustained during the policy period in accordance with insurance policy and benefit program limits. The State assumes all risks for the following:

(1) claims of covered employees for health benefits covered through South Carolina Public Employee Benefit Authority ("PEBA") Insurance Benefits; and not applicable for worker's compensation injuries; and
(2) claims of covered employees for basic long-term disability and group life insurance benefits (PEBA Insurance Benefits and PEBA Retirement Benefits).

Employees elect health coverage through the State's self-insured plans except for employee dental insurance for which the Authority is self-insured. Risk exposure for the dental plan is limited by plan provisions. Additional group life and long-term disability premiums are remitted to commercial carriers. The Authority assumes the risk for claims of employees for unemployment compensation benefits and pays claims through the State's self-insured plan.

Nuclear Insurance - The maximum liability for public claims arising from any nuclear incident has been established at $13.523 billion by the Price-Anderson Indemnification Act. This $13.523 billion would be covered by nuclear liability insurance of $450.0 million per reactor unit, with potential retrospective assessments of up to $137.6 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed $20.5 million per incident, per year). Based on its one-third interest in Summer Nuclear Unit 1, the Authority could be responsible for the maximum assessment of $45.9 million, not to exceed approximately $6.8 million per incident, per year. This amount is subject to further increases to reflect the effect of (i) inflation, (ii) the licensing for operation of additional nuclear reactors and (iii) any increase in the amount of commercial liability insurance required to be maintained by the NRC. Additionally, Dominion and the Authority maintain, with Nuclear Electric Insurance Limited ("NEIL"), $1.500 billion primary and $1.250 billion excess property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. Dominion and the Authority also maintain an excess property insurance policy with European Mutual Association for Nuclear Insurance (EMANI) to cover property damage and outage costs up to $415.0 million resulting from an event of non-nuclear origin. Dominion and the Authority also maintain accidental outage insurance to cover replacement power costs (within policy limits) associated with an insured property loss. In addition to the premiums paid on these policies, Dominion and the Authority could also be assessed a retrospective premium, not to exceed ten times the annual premium of each policy, in the event of property damage to any nuclear generating facility covered by NEIL. Based on current annual premiums and the Authority's one-third interest, the Authority's maximum retrospective premium would be approximately $7.0 million for the primary policy, $3.6 million for the excess policies and $1.8 million for the accidental outage policy.

The Authority is self-insured for any retrospective premium assessments, claims in excess of stated coverage or cost increases due to the purchase of replacement power associated with an uninsured event. Management does not expect any retrospective assessments, claims in excess of stated coverage or cost increases for any periods through December 31, 2021.

Clean Air Act - The Authority endeavors to ensure that its facilities comply with all applicable environmental regulations and standards under the Clean Air Act ("CAA"). The Authority continues to review proposed greenhouse gas regulations and legislation to assess potential impacts to its operations. The latest rulemaking occurred on June 24, 2019, when the EPA issued the final Affordable Clean Energy ("ACE") Rule following the repeal of the Clean Power Plan ("CPP"). The ACE Rule, which established heat rate improvement ("HRI") measures as the best system of emissions reduction ("BSER") for CO2 emissions from existing coal-fired EGUs, was vacated and remanded by the D.C. Circuit Court of Appeals on January 19, 2021. On October 29, 2021, the U.S. Supreme Court agreed to review the lower court's ruling, considering the scope of the EPA's authority to regulate carbon. A decision is expected in 2022. The Authority cannot currently predict the outcome or future scope, timing, and costs associated with any CO2 emissions requirements.

Safe Drinking Water Act - The Authority continues to monitor regulatory issues impacting drinking water systems at the Authority's regional water systems, generating stations, substations and other auxiliary facilities. DHEC has regulatory authority of potable water systems in South Carolina under The State Primary Drinking Water Regulation, R.61-58; the Authority endeavors to manage its potable water systems in compliance with R.61-58.

On the federal level, the EPA has recently announced its intention to implement a national program to evaluate and regulate a category of organic contaminants known as per- and poly[1]fluoroalkyl substances ("PFAS"). The Authority does not anticipate significant implications for its power-related facilities but does anticipate new requirements for its Regional Water Systems because the first new requirements appear to be related to drinking water. Specifically, the Strategic Roadmap 2021-2024 announced by the EPA on October 18, 2021 states that public water systems will be required to participate in a nationwide monitoring program for PFAS in drinking water during a 12-month period sometime between the beginning of 2023 and the end of 2025. The EPA issued a final rule on December 27, 2021, and the Authority is evaluating its new obligations. The EPA also announced a proposed rule to establish national drinking water standards for perfluorooctaonoic acid ("PFOA") and perfluorooctane sulfonic acid ("PFOS") - and perhaps other chemicals in the PFAS category - with a proposed regulation expected in the fall of 2022. The Authority will comply with any applicable new standards that are issued.

In addition, the EPA's Revised Lead and Copper Rule (86 FR 4198) became effective on December 16, 2021, with a compliance date of October 16, 2024. This rule is expected to have only a minimal impact on the Authority's Regional Water Systems as they have a limited transmission system that is completely constructed from cement lined ductile iron pipe. Changes in requirements for monitoring frequency, corrosion control treatment, and sampling procedure will be the primary effects to the Regional Water Systems. The Cross Generating Station includes a Non-Transient Non-Community Water System and will be required to conduct an inventory of on-site drinking water pipes.

Clean Water Act - The Clean Water Act ("CWA") prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System ("NPDES") permit program. DHEC has been delegated NPDES permitting authority by the EPA and administers the NPDES permit program for the State. Wastewater discharges from the generating stations and the regional water plants are governed by NPDES permits issued by DHEC. Further, the storm water from the generating stations must be managed in accordance with the State's NPDES Industrial General Permit for storm water discharges. Storm water from construction activities must also be managed under the State's NPDES General Permit for storm water discharges from construction activity. The Authority endeavors to operate in compliance with these permits.

EPA issued their final rule regarding Section 316(b) of the CWA on August 15, 2014. The rule establishes requirements for cooling water intake structures ("CWISs") at existing facilities. Section 316(b) of the CWA requires that the location, design, construction and capacity of CWISs reflect the best technology available (BTA) for minimizing adverse environmental impacts. The Authority will continue to work with the regulatory agencies on implementation as required. The Authority believes compliance costs are not significant.

EPA regulates oil spills prevention and preparedness under the CWA, Spill Prevention Control and Counter-measures ("SPCC"). These regulations require that applicable facilities, which include generating stations, substations and auxiliary facilities, maintain SPCC plans to meet certain standards. The Authority continually works to be in compliance with these regulations. In addition to the SPCC requirements, the Myrtle Beach and Hilton Head Gas Turbine sites are subject to 40 CFR 112.20 and 112.21 requirements for Facility Response Plans (FRP).

EPA had also been developing a new rule specifying requirements for spill prevention and preparedness for chemicals stored in aboveground storage tanks. Under a consent decree issued on February 16, 2016, EPA was required to create new regulations that established procedures, methods, equipment, and other requirements to prevent hazardous substance discharges. On June 25, 2018, EPA published a proposed rule that determined no additional actions are necessary to prevent these discharges. The public comment period for the proposed rule closed on August 24, 2018, and on September 3, 2019, EPA published a final rule stating that they are not establishing new requirements for hazardous substances under the CWA. In February of 2020, EPA entered into a consent decree with a number of environmental plaintiffs describing their intent to develop new regulations for such chemicals over the next twenty-four months, with a final action required within thirty months. The Authority does not expect any significant compliance costs associated with these regulations.

A revision to the NPDES Steam Electric Effluent Limitation Guidelines ("ELG") rule became effective on January 4, 2016. The guidelines proposed stricter performance standards that required upgrades and installation of additional wastewater treatment systems for the Winyah and Cross Generating Stations. The EPA later revised this ELG rule to require compliance starting on November 1, 2020. In April 2017, the EPA postponed some compliance dates in the rule and stated its intention to draft a new rule. In April 2019, the U.S. Court of Appeals for the Fifth Circuit remanded portions of the ELG rule because it determined that some of the standards were not sufficiently stringent. On October 13, 2020, EPA published a new rule in the Federal Register that has revised compliance limits, as well as new subcategories for low-capacity boilers and facilities facing retirement. Construction on many of the treatment systems and equipment required to comply with the rule is complete and the Authority expects the remaining cost of compliance at Cross to be approximately $98 million for FGD wastewater treatment. The Authority's board has voted to retire Winyah by 2028 and utilize the retirement exemption in the ELG Rule, so costs there are believed to be insignificant. ELG requirements under the 2020 rule, along with any new state-defined limits, will be included in revised NPDES discharge permits that are currently being developed by the South Carolina Department of Health and Environmental Control ("DHEC"). While not final, draft permits for Cross and Winyah Generating Stations were recently put on public notice by DHEC. These draft permits reflect a reasonable schedule for implementation of FGD wastewater treatment at Cross and the Authority's intention to retire Winyah. The ability to switch to other compliance strategies for FGD wastewater is also not precluded, and the Authority has submitted notices of planned participation for relevant compliance subcategories. It remains possible that there could be changes in the final permits; any such additional requirements and associated costs are not yet known. While the 2020 rule remains in force at this time, the EPA announced a new rulemaking initiative in the Federal Register ("FR") on July 26, 2021, stating its intention to reevaluate FGD wastewater and bottom ash transport water limits and compliance alternatives in a new rule, which will be published as a proposed rule in the fall of 2022. The FR statement announced the EPA's intention that permittees and state permitting authorities follow the 2020 rule until a new rule is published. In light of this new upcoming rulemaking, the Authority is working to evaluate its options. At this time, it is not possible to identify a final compliance target, method of compliance, or associated costs with the new rulemaking.

On October 22, 2019, the Army Corps of Engineers and the EPA published a final rule repealing the 2015 Waters of the U.S. ("WOTUS") Rule, which had required that more water features be regulated as WOTUS, with additional permitting and mitigation requirements and costs. On April 21, 2020, the Army Corps of Engineers and the EPA published the Navigable Waters Protection Rule ("NWPR") to redefine Waters of the U.S., and the final rule became effective on June 22, 2020. The April 2020 final rule provided additional clarity and addressed many of the concerns posed by the broad 2015 rule, including exclusions for ditches and waste treatment systems. The rule also maintained exclusions for groundwater, ephemeral features and diffuse stormwater run-off, and artificial lakes and ponds created because of impounding non-jurisdictional waters. Numerous environmental groups filed challenges to the NWPR following its publication, including challenges to the waste treatment system exclusion. On June 9, 2021, the EPA announced its intention to initiate a new rulemaking process that "restores the protections in place" prior to the 2015 WOTUS rule and to develop a more durable definition. On September 3, 2021, the EPA and the Army Corps published an update that they have halted implementation of the NWPR, so effectively the agencies will interpret waters of the United States consistent with the pre-2015 regulation until further notice. Existing jurisdictional determinations remain valid for five years from the date of issue. The EPA and Army Corps published a proposed rule on November 18, 2021 to replace the NWPR with a revised version of the 1986 WOTUS regulations with amendments reflecting the Agencies' interpretation of Supreme Court Decisions in the Rapanos judgement. Through adopting both the "relatively permanent" test and "significant nexus" test, the proposed rule would establish a broader geographic scope of WOTUS jurisdiction than either the NWPR or the 1986 regulations. At this time, it is not possible to identify specific impacts, but it is likely that additional time and cost for any new construction will be necessary in the future to account for greater uncertainty regarding the definition of Waters of the U.S.

Hazardous and Non-Hazardous Substances, Solid Wastes and Coal Combustion Byproducts - Under the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") and Superfund Amendments and Reauthorization Act ("SARA"), the Authority could be held responsible for damages and remedial action at hazardous waste disposal facilities utilized by it, if such facilities become part of a Superfund effort. Moreover, under SARA, the Authority must comply with a program of emergency planning and a "Community Right-To-Know" program designed to inform the public about more routine chemical hazards present at the facilities. Both programs have stringent enforcement provisions. Section 311 of the CWA imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. CERCLA provides for the reporting requirements to cover the release of hazardous substances into the environment. The Authority endeavors to comply with the applicable provisions of TSCA, CERCLA and SARA, but it is not possible to determine if some liability may be imposed in the future for past waste disposal or compliance with new regulatory requirements. The Authority strives to comply with all aspects of the Resource Conservation and Recovery Act ("RCRA") regarding appropriate disposal of hazardous wastes. The Authority's corporate policy titled Solid, Universal and Hazardous Waste (Policy Number 2-42-02) and the Corporate Waste Management Guidance Document provide guidance for the proper management and monitoring of solid, universal and hazardous waste for environmental and regulatory compliance. Additionally, the EPA regulations under the Toxic Substances Control Act ("TSCA") impose stringent requirements for labeling, handling, storing and disposing of polychlorinated biphenyls ("PCBs") and associated equipment. The Authority's corporate policy titled PCB Management (Policy Number 5-23-04) and the PCB Management Plan provide guidance for the proper management and monitoring of PCBs for environmental and regulatory compliance.

The Solid Waste Disposal Act and Energy Policy Act give EPA authority to regulate Underground Storage Tanks ("USTs"). EPA regulations concerning USTs are contained in 40 CFR Parts 280-282. DHEC was granted state program approval in 2002 and regulates USTs under R. 61-92, Part 280. This regulation provides requirements for the design, installation, operation, closure, release detection, reporting and corrective action and financial responsibility. The Authority's corporate policy titled Underground Storage Tanks (Policy Number 2-11-03) provides guidance for the proper management and monitoring of USTs for environmental and regulatory compliance.

The Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash, scrubber sludge and gypsum. These wastes, known as Coal Combustion Residuals ("CCRs"), are exempt from hazardous waste regulation under the RCRA. On April 17, 2015, EPA published the CCR Rule establishing comprehensive requirements for the management and disposal of CCRs. The rule regulates CCRs as a RCRA Subtitle D, nonhazardous waste and had an effective date of October 19, 2015. The Authority continues to comply with the CCR Rule through groundwater monitoring, assessment of corrective measures and internet postings of CCR Rule reports. Long-term compliance plans to address groundwater include pond closures and utilization of Class 3 landfills at the Cross and Winyah Generating Stations for disposal of CCRs. Beneficial use of ash and gypsum results in removal of CCRs from ponds to support closure and fewer CCRs being disposed of in the on-site landfills. The Class 3 landfill at Winyah Generating Station has been in operation since November 2018. DHEC issued approval to operate two newly constructed cells of the Winyah Class 3 landfill on December 20, 2021. The Cross Generating Station's Class 3 landfill continues in operation. These two Class 3 landfills are subject to the CCR Rule. The surface impoundments subject to the CCR Rule are located at the Cross and Winyah Generating Stations. These CCR impoundments have triggered closure because they are unlined and do not meet the aquifer location standard. Additionally, a subset of these CCR impoundments do not meet the groundwater protection standards for one or more constituents and are thus in a Corrective Action program. As of the April 11, 2021 CCR rule deadline, all ponds subject to the CCR Rule are no longer receiving any CCR or non-CCR waste streams.

Other CCR rulemakings are pending and will be monitored to address any requirements that impact the Authority. The EPA has issued an advanced notice of proposed rulemaking ("ANPRM") regarding regulating legacy impoundments and this proposed rulemaking is expected in late 2022 with a final rule to follow about one year later. Under this rulemaking, other ponds could become subject to the CCR Rule, including the Jefferies Generating Station ash pond and possibly the Grainger Generating Station ash ponds, even though the Grainger ash ponds have completed closure in accordance with DHEC's requirements. Other rulemakings which are expected to be issued in the near future include a Federal CCR Permit Program with procedures for CCR units to obtain permits in non-participating states, which includes South Carolina, and an additional closure option for units that are closing by removal of CCR but cannot complete groundwater corrective action within the rule's prescribed closure timeframes.

Closure plans for the Jefferies Generating Station Ash Pond and for the Winyah West Ash Pond have been approved by DHEC and closure is in progress, with regulatory deadlines of 2030. These ponds are not currently subject to the CCR Rule. However, as noted above, pending CCR rulemakings could regulate inactive impoundments at closed facilities. The Cross Bottom Ash Pond and the remaining ponds at the Winyah Generating Station (A Ash Pond, B Ash Pond, South Ash Pond, and Units 3 & 4 Slurry Pond) are subject to both the CCR Rule's closure requirements and to DHEC closure regulations. A closure plan for the Winyah A Ash Pond has been approved by DHEC and closure is in progress. Plans are being developed and implemented to facilitate closure of the remaining ponds by the CCR Rule's regulatory deadlines. The ponds will be closed through excavation and beneficial use of materials or through disposal in the on-site industrial Class 3 solid waste landfills on site at Cross and Winyah. For the Cross Bottom Ash Pond, closure by removal is the selected closure strategy and monitored natural attenuation is the selected groundwater remedy so that it meets groundwater protection standards. Closure by removal is also the strategy for the Winyah CCR ponds and a similar groundwater remediation strategy is being evaluated. Four ponds (Winyah Slurry Pond 2, Grainger Ash Pond 1, Grainger Ash Pond 2, and the Cross Gypsum Pond) have already completed closure in accordance with DHEC's requirements. The Authority estimates approximately $315 million remaining to spend between 2022 and 2031 for pond closures associated with the CCR Rule, and these costs are included in current capital budgets. These costs are also part of the asset retirement obligation.

Wildlife – The Authority's operations have the potential to impact threatened and endangered species, birds, and other wildlife protected by the Endangered Species Act ("ESA"), Migratory Bird Treaty Act ("MBTA"), National Environmental Policy Act ("NEPA"), and additional state and federal requirements. Penalties for violations can be substantial and include criminal liability. The Authority endeavors to ensure that its facilities, operations, and projects comply with all applicable wildlife protection requirements.

Pollution Remediation Obligations – The Authority follows GASB 49, which addresses standards for pollution (including contamination) remediation obligations for activities such as site assessments and cleanups. GASB 49 does not include standards for pollution remediation obligations that are addressed elsewhere. Examples of obligations addressed in other standards include pollution prevention and control obligations for remediation activities required upon the retirement of an asset, such as ash pond closure and post-closure care and nuclear power plant decommissioning.

On December 31, 2020, the Authority was notified by the South Carolina Department of Health and Environmental Control ("DHEC") that the Authority was required to submit a Site-Specific Work Plan ("SSWP") for an Initial Ground Water Assessment ("IGWA") under the South Carolina Pollution Control Act (SC Code Ann. § 48-1-50(6), § 48-1-50(20), and § 48-1-50(21)), for a property within the Authority's FERC project boundaries that is currently occupied by a commercial lessee. An underground pipe on the property was damaged by employees of a telecommunications company during installation of underground wiring and an estimated 800 gallons of gasoline leaked into the surrounding soil. DHEC has informed the Authority that DHEC considers the Authority responsible for any necessary remediation activities, although the Authority is currently negotiating with the telecommunications company on a cost sharing agreement. After the IGWA results were received and indicated groundwater contamination, DHEC requested a Tier II assessment SSWP for additional soil and groundwater sampling. The Tier II results were submitted to DHEC on September 14, 2021. Subsequent activity resulted in DHEC approving an Evacuation Corrective Action Plan and Well Installation Plan on November 18, 2021. We expect the Corrective Action Plan to cost approximately $101,000 plus $12,900 per year in annual sampling costs for a period of up to five years. Santee Cooper is working with other parties to share costs of the cleanup. Implementation of the Corrective Action Plan is planned for 2022.

A property exists within the Authority's FERC project boundaries that is currently occupied by a commercial lessee, Packs Landing Marina. As part of a proposed SCDOT right-of-way project, a Phase II environmental assessment was conducted in the early 2000s that identified soil and groundwater hydrocarbon contamination from underground and/or above ground fuel tanks at the site. Based on that information, DHEC began working with the lessee to address the contamination but was unsuccessful. In response, DHEC contacted the Authority as the property owner. In 2014, the Authority was notified by DHEC that, based on the groundwater monitoring report received in August 2013, the submittal of a Tier II Assessment Plan was required. The Authority agreed to monitor the progress of the environmental work and assist with financing cost of environmental assessment for the leaseholder. Work has been conducted on the site since 2013 through DHEC-approved workplans. On March 17, 2021, DHEC issued a directive to Packs Landing Marina for a Site-Specific Work Plan (SSWP) to conduct additional testing for creosote found in sample results at the site. Negotiations for a Voluntary Cleanup Contract are taking place for the creosote aspect of the site while work on the hydrocarbon component continues, and DHEC has been provided the results detailing the most recent field investigation.

No pollution remediation liabilities were recorded for the years ended December 31, 2021 and 2020.

FERC Hydroelectric License - The Authority operates its Jefferies Hydro Station and certain other property, including the Pinopolis Dam on the Cooper River and the Santee Dam on the Santee River, which are major parts of the Authority's integrated hydroelectric complex, under a license issued by the FERC pursuant to the Federal Power Act ("FPA"). The project is currently undergoing relicensing and a Notice of Intent ("NOI") to relicense was filed with the FERC on November 13, 2000. The final license application was filed March 15, 2004. Due to a number of Additional Information Requests and a delay in the consultation process between FERC and the National Marine Fisheries Service ("NMFS"), the relicensing process has extended beyond the March 31, 2006 license expiration date. The FERC has issued a standing annual license renewal until a final license is issued. The FERC issued its Final Environmental Impact Statement ("EIS") in October 2007. The South Carolina Department of Natural Resources, the U.S. Fish and Wildlife Service, and the Authority jointly signed and filed a settlement agreement with the FERC in May 2007 that, among other things, identifies fish passage and outflow guidelines during the term of the next license. The NMFS chose not to join in that settlement agreement and in January 2020 submitted a second modified prescription for mandatory fishway conditions under §18 of the FPA, flow recommendations under §10 of that Act, and a final biological opinion for the endangered short nose sturgeon and Atlantic sturgeon under Section 7 of the Endangered Species Act ("ESA"). In July 2020, the FERC updated the federally listed threatened, endangered, candidate or proposed species, and designated or proposed critical habitat within the project boundary or potentially affected by project operations. In March 2021, the FERC accepted the Authority's updated stability analysis for the Santee Dams to address consequences of continuous spilling at the spillway gang gates and permanently higher tailwater levels due to the proposed higher minimum flows. All other known requirements are complete, and the Authority expects issuance of a new license is imminent. Total implementation costs are estimated to be between $84 million and $179 million. Santee Cooper has recorded approximately $400,000 in capital assets for the FERC Hydroelectric license through December 31, 2021.

Homeland Security - The Department of Homeland Security ("DHS") was established by the Homeland Security Act of 2002, a portion of which relates to anti-terrorism standards at facilities which store or process chemicals. The Chemical Facility Anti-Terrorism Standards ("CFATS") program identifies and regulates high-risk chemicals facilities to ensure they have security measures in place to reduce the risk associated with these chemicals. The Authority has been proactive in striving to comply with these evolving regulations by conducting valid threat and risk assessments to the facilities regulated by the CFATS program, also referred to as 6 CFR, Part 27. Once completed, the assessments become sensitive, federally controlled documents and are stored in accordance with all federal and state guidelines attendant to critical infrastructure information protection.

Legislative Matters - On June 8, 2021, the General Assembly passed, and on June 15, 2021, the Governor signed into law Act 90 of 2021 (H.3194), which establishes reforms by amending the state laws applicable to the Authority. Act 90 of 2021, among other things, includes the following provisions:

- Act 135 Extension. Extended the expiration date (from May 31, 2021 to December 31, 2021) of Act 135, which established certain operational guidelines for the Authority. Although Act 135 was extended, Act 90 of 2021 removed the requirement in Act 135 that the ORS conduct monthly reviews of the Authority and further authorized the Authority to proceed with the plan for the closing of the Winyah Generating Station and to enter into financial transactions for, among other purposes, converting variable rate debt to fixed rate debt and obtaining lower interest rates on existing debts, provided that overall debt load may not be increased by any such transaction.

- Joint Bond Review Committee Approval Requirements for Bonds and Real Estate Transfers. Requires the JBRC to approve, reject, or modify a proposed issuance by the Authority of its (1) bonds, (2) notes, or (3) other indebtedness, including any refinancing that does not achieve a savings in total debt service. The JBRC has determined that any refinancing transactions that are not typically utilized by the State will require its approval. Act 90 of 2021 provides that JBRC approval is not required for the issuance of short-term or revolving-credit debt for the management of the Authority's day-to-day operations and financing needs. If the JBRC does not approve, reject, or modify a request for approval of a proposed debt issuance within sixty days, the issuance is deemed approved. A proposed debt issuance that receives JBRC approval may be issued across multiple series and over a three-year period of time.

  With the exception of encroachment agreements, rights of way, or lease agreements made by the Authority for property within the Federal Energy Regulatory Project boundary, a transfer of any interest in real property by the Authority, regardless of the value of the transaction, requires approval, rejection, or modification by the JBRC and the Authority is required, by September first of each year, to provide an annual report to the JBRC regarding every transaction involving an interest in real property executed during the preceding twelve months.

- Changes to Retail Rates Process. Establishes a retail rate process ("Retail Rate Process") for the Authority requiring the Authority to (i) adopt and publish pricing principles that balance certain factors including, but not limited to, adherence to the Authority's mission to be a low-cost provider, reliability, transparency, preservation of financial integrity, equity among customer classes, gradualism in adjustments to its pricing and rate schedule type, adequate notice to customers, relief mechanisms for financially distressed customers, and review of compliance with bond covenants, and (ii) submit to the ORS for its review and comment any proposed rate adjustments presented to the Board for the Board's approval.

  Act 90 of 2021 also establishes procedures for challenges to rates and authorizes the Authority to place adjusted rates and charges into effect on an interim basis not exceeding 18 months if needed to avoid a default of its obligations and to ensure proper maintenance of its System. The South Carolina Supreme Courts may not substitute its judgment for the judgment of the Board as to questions of fact when reviewing rate adjustments approved by the Board pursuant to Act 90 of 2021 which have been authorized by law and the remedy for a successful rate challenge is a prospective adjustment of a new rate.

- Construction, Acquisition and Purchase Requirements. Imposes certain limitations and approval requirements on the Authority with respect to the construction, acquisition, and purchase of major utility facilities, including that the Authority may not enter into a contract for the acquisition of a major utility facility without the prior approval of the SCPSC. In addition, the Authority is required to file for SCPSC approval of a program for the competitive procurement of energy, capacity, and environmental attributes from renewable energy facilities to meet needs for new generation resources identified by the Authority in its integrated resource plans or other planning processes. The Authority also may not enter into a contract for the purchase of power with a duration longer than ten years without approval of the SCPSC unless the transaction is either (i) subject to the exclusive jurisdiction of FERC or another federal agency or (ii) a purchase of renewable power through a SCPSC approved competitive procurement.

- Board of Directors Qualifications. Revises the terms and qualifications for membership on the Board, provides for two non-voting ex-officio members, establishes their duties and responsibilities, and provides that violations of such duties and responsibilities constitutes grounds for removal by the Governor. Act 90 of 2021 provides a transition to a new board over a four-year period, changes board terms from seven years to four years and creates a three-term limit. Act 90 of 2021 establishes new experience and educational requirements for board members and directs the appointing authority, the Governor, to consider diversity when making appointments. Two non-voting ex officio members, appointed by the Authority's largest customer Central, are added to the Board.

  Each Board member is required to discharge his duties, in good faith, with the care an ordinarily prudent person in a like position would exercise under similar circumstances and in a manner he or she reasonably believes to be in the best interests of the Authority, which involves a balancing of, among other things, preservation of the financial integrity of the Authority and its operations, the interest of the Authority's residential, commercial and industrial retail customers in reliable, adequate, efficient, and safe service, at just and reasonable rates, regardless of customer class and the exercise of the powers of the Authority set forth in the Act in accordance with good business practices and the requirements of applicable licenses, laws, and regulations.

- Certain Compensation, Benefit and Severance Packages Subject to Review and Approval. Any compensation package, severance package, payment or other benefit conferred upon the Authority CEO or member of the Board of the Authority must first be reviewed and approved by the Agency Head Salary Commission of the State Fiscal Accountability Authority. Additionally, any employment contracts or retention contracts that last longer than five years, and all contract extensions, must be reviewed by the Agency Head Salary Commission. Any payment made or benefit given in violation of Act 90 of 2021 is subject to a claw-back of the payment or benefit in a legal action brought by the State Attorney General.

- Service Territory. Provides the process by which the Authority may enter into agreements with other electric suppliers on the reassignment of service areas.

- Authority and Jurisdiction of ORS, JBRC and SCPSC. Establishes the authority and jurisdiction of the ORS with respect to the Authority and sets forth certain on-going reporting and compliance requirements for the Authority, including filing of an integrated resource plan with the SCPSC, filing an annual report on transactions involving real property to the JBRC, and submission of books, records and other information requested by the ORS.

Act 90 of 2021 expressly states that the Retail Rate Process established by such Act does not limit or derogate from the State's covenants in Sections 58-31-30 and 58-31-360 of the Code of Laws of South Carolina 1976, as amended, not to impair, alter, limit or restrict the Authority's power to establish rates and charges sufficient to provide for payment of its expenses and debt service on its obligations, and those covenants are reaffirmed.

During the second half of 2021 and related to Act 90 of 2021, the Joint Bond Review Committee considered and approved several finance and real estate transactions of the Authority, the Agency Head Salary Commission approved a six-month contract extension and annual performance measures for Authority CEO Mark Bonsall, and the South Carolina Public Service Commission held an *ex parte* hearing related to its new regulatory authority over the Authority.

The Electric Market Reform Measures study committee established by Act 187 of 2020 met twice in 2021. This electric market study committee is made up of 8 legislators, 4 from the SC Senate and 4 from the SC House. The study committee is charged with analyzing whether South Carolina should consider any changes to its electric market structure. It is expected that this study committee will issue an interim report in 2022.

The South Carolina General Assembly adjourned its legislative session in December 2021. The General Assembly will finish its two-year legislative session in 2022.

Legal Matters - Except as noted below, there are no actions, suits, or governmental proceedings pending or, to the knowledge of the Authority, threatened before any court, administrative agency, arbitrator or governmental body which would, if determined adversely to the Authority, have a material adverse effect on the Authority's financial condition, or the Authority's ability to transact its business or meet its obligations under the Revenue Obligation Resolution. The Authority is vigorously defending any liability in all pending litigation; however, certain matters may be subject to trial by a jury or judge, which serves as the final trial trier of facts and awards. Alternatively, the Authority may decide to enter settlement negotiations to resolve such disputes. The Authority is unable to predict the outcome of the matters described below. Adverse decisions or determinations could delay or impede the Authority's operation or construction of its existing or planned projects, and/or require the Authority to incur substantial additional costs. Such results could materially adversely affect the Authority's revenues and, in turn, the Authority's ability to pay debt service on its bonds.

Recently Settled Litigation Matters

(a) Hearn v. South Carolina Public Service Authority

On August 16, 2017, Plaintiff George Hearn, on behalf of a putative class of retail customers, filed a class action complaint in Horry County alleging the Authority acted negligently when it decided to build the Pee Dee coal generating facility in Florence County and acted negligently when it decided to cancel construction of the facility and was negligent in accounting for the Pee Dee assets. The specific claims in the complaint include breach of duty to ratepayers, breach of contract, declaratory judgment/injunctive relief, unjust enrichment, money had and received, affirmative injunctive relief, and violation of due process. Plaintiffs claimed damages of $600 million. The parties agreed to settle the matter with the Authority paying $12,500,000 to a common benefit fund in exchange for a full release of all claims that were or could have been brought by the class (defined as all residential and business retail customers who received power and energy from the Authority and who had accounts with the Authority between November 1, 2009 and February 28, 2021) and which arise out of or are related to the Pee Dee Plant. The court entered an order finally approving the settlement on October 8, 2021.

(b) *Cook et al. v. South Carolina Public Service Authority et al.*

On July 31, 2020, the South Carolina Court of Common Pleas entered an Amended Order Approving Settlement, which dismissed a putative class action filed in August of 2017 against the Authority in connection with the Authority's July 2017 decision to suspend construction of Summer Nuclear Units 2 and 3 (Jessica S. Cook et al. v. Santee Cooper, Santee Cooper's Board of Directors (certain former and current Directors named), SCE&G, SCANA Corporation, SCANA Services, Inc., Palmetto Elec. Coop., & Central Electric. Power Coop.) (the "Cook Settlement Agreement"). The *Cook* Settlement Agreement generally provides for the dismissal and the release of all claims belonging to the class members against the defendants, including the claims against the Authority. In exchange for dismissal and release of the claims, Dominion and the Authority agreed to make certain payments to a Common Benefit Fund (the "Common Benefit Fund") in the amount of $520 million to be paid to class members. The Authority's portion of the payments to the Common Benefit Fund is $200 million, to be paid in three annual installments in each of the third quarters of 2020, 2021 and 2022, in the amount of $65 million, $65 million, and $70 million, respectively. The Authority's payment for 2020 was made on September 25, 2020, and the payment for 2021 was made on September 24, 2021. In addition, the Authority agreed to hold its rates consistent with rates projected in the Authority's Act 95 Reform Plan beginning in August of 2020 and (i) for the customers other than Central whose rates are subject to the rate lock, effective for all bills rendered on or after August 16, 2020 through all bills rendered on or before January 15, 2025, and (ii) for Central, through service rendered on or before December 31, 2024. The Cook Settlement Agreement requires the Authority to file an annual report demonstrating compliance with certain terms of the Agreement. On April 30, 2021, the Authority filed its first report. As allowed by the Agreement, on June 9, 2021, Central filed a Request for the Appointment of an Independent Auditor to review the Authority's compliance as to three transactions: (1) using funds specifically allocated for capital projects to retire a scheduled balloon payment in 2023 while borrowing new money to fund existing capital project needs, (2) restructuring existing debt, and (3) using funds on hand to pay the first $65 million installment to the Common Benefit Fund. As stated in its 2020 Annual Compliance Report, the Authority's position is that it is in full compliance with the Agreement, the Agreement does not prohibit the Authority from issuing or restructuring debt nor does it prohibit the Authority from using funds on hand to pay installments due to the Common Benefit Fund. The Authority's response to Central's audit request was submitted on July 12, 2021. The court deferred approving or denying Central's request.

Pending Matters or Disputes

(a) Central Agreement Audit Dispute

Following an annual audit of the Authority's records as permitted under the Central Agreement, Central has taken issue with the Authority's treatment of the Summer Nuclear Units 2 and 3 associated regulatory asset under the Central Agreement's cost of service model. Central's treatment of the regulatory asset, if applied, would result in the return to Central of over $50 million for fiscal years 2017, 2018 and 2019, and a reduction in future contributions from Central in a yet undetermined amount. The Authority has responded to Central noting its disagreement with Central's position. The parties are proceeding with determining a means for resolving the dispute.

(b) Central Arbitration Notice

On September 23, 2021, Central tendered a Notice of Arbitration, as permitted under the Central Agreement, presenting questions related to the Authority's accounting for gypsum expenses and revenues in conjunction with the Authority's contract with American Gypsum. The Authority submitted a response denying the allegations on October 15, 2021. A full arbitration Tribunal is expected to be selected in early 2022, after which the arbitration will occur. Court proceedings may follow the Tribunal's decision pursuant to the terms of the Central Agreement.

(c) South Carolina Public Service Authority v. U.S. Army Corps of Engineers

The Authority filed a claim on October 2, 2015 against the COE seeking a determination that the Rediversion Contract between the Authority and the COE does not require the Authority to credit the COE for a capacity value surcharge and that the COE owes the Authority approximately $1.4 million in contract payments for 2015. The Rediversion Contract governs the operation of the St. Stephen Hydro Plant and the obligations of the parties related to the Plant's operations. The COE denied the claim and asserted the Authority was required to pay the credit and a credit in the amount of $716,874 was due to the COE for 2015. The Authority appealed the decision to the Armed Services Board of Contract Appeals ("ASBCA") and the COE counterclaimed. The parties asked the ASBCA to determine the rights under the contract.

On July 22, 2020, the Board denied the Authority's appeals and remanded to the parties for "negotiation for the value of the additional capacity for the final 20 years of the contract performance period based on the contract." Negotiations are ongoing.

Note 11 – Retirement Plans

The South Carolina Public Employee Benefit Authority ("PEBA"), which was created July 1, 2012, administers the various retirement systems and retirement programs managed by its Retirement Division. PEBA has an 11-member Board of Directors, appointed by the Governor and General Assembly leadership, which serves as co-trustee and co-fiduciary of the systems and the trust funds. By law, the Budget and Control Board (restructured into the Department of Administration on July 1, 2015), which consists of five elected officials, also reviews certain PEBA Board decisions regarding the funding of the South Carolina Retirement System ("SCRS") and serves as a co-trustee of the Systems in conducting that review.

PEBA issues an Annual Comprehensive Financial Report ("ACFR") containing financial statements and required supplementary information for the Systems' Pension Trust Funds. The ACFR is publicly available through the Retirement Benefits' link on PEBA's website at www.peba.sc.gov, or a copy may be obtained by submitting a request to PEBA, PO Box 11960, Columbia, SC 29211-1960. PEBA is considered a division of the primary government of the state of South Carolina, and therefore, retirement trust fund financial information is also included in the comprehensive annual financial report of the State.

Plan Description - Substantially all Authority regular employees must participate in one of the components of the SCRS, a cost sharing, multiple-employer public employee retirement system, which was established by Section 9-1-20 of the South Carolina Code of Laws.

Benefit Provided - Vested employees ("Class Two Members") who retire at age 65 or with 28 years of service at any age are entitled to a retirement benefit, payable monthly for life. Vested employees ("Class Three Members") who retire at age 65 or meet the "rule of 90 requirements" (i.e., the total of the member's age and the member's creditable service equals at least 90 years), are entitled to a retirement benefit, payable monthly for life. The annual benefit amount is equal to 1.82 percent of their average final compensation times years of service. Benefits fully vest on reaching five years of service for Class Two Members and eight years for Class Three Members. Reduced retirement benefits are payable as early as age 60 with vested service or 55 with 25 years of service for Class Two Members. The SCRS also provides death and disability benefits. Benefits are established by State statute.

Article X, Section 16 of the South Carolina Constitution requires that all State-operated retirement plans be funded on a sound actuarial basis. Title 9 of the South Carolina Code of Laws (as amended) prescribes requirements relating to membership, benefits and employee/employer contributions.

Effective July 1, 2002, new employees have a choice of the type of retirement plan in which to enroll. The State Optional Retirement Plan ("State ORP") which is a defined contribution plan is an alternative to the SCRS retirement plan which is a defined benefit plan. The contribution amounts are the same, (9.00 percent employee cost and 16.41 percent employer cost); however, under the State ORP, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 11.41 percent is contributed to the SCRS. As of December 31, 2021, the Authority had 91 employees participating in the State ORP and consequently the related payments are not material.

Effective July 1, 2017, the Retirement System Funding and Administration Act of 2017 (the "Act") increased employer retirement contribution rates by 2 percent to 13.56 percent for SCRS. The employer contribution rate for the State ORP was increased to 13.56 percent, with 5 percent of the employer contribution being remitted directly to the participant's State ORP investment provider. The employer rate will continue to increase annually by 1 percent through July 1, 2023, with the ultimate employer rate reaching 18.56 percent. Employee rates for SCRS and the State ORP increased to and are capped at 9 percent. Employer and employee contribution rates may be decreased in equal amounts once the system is 85 percent funded. The employee contribution rate may not be less than ½ of the normal cost for the system. The Act also reduced the funding period for unfunded liabilities from 30 to 20 years over the next 10 years as well as lowered the current assumed annual rate of return from 7.5 percent to 7.25 percent. The assumed annual rate of return expired July 1, 2021 and will every four years thereafter. PEBA must propose an annual rate of return every four years, which will become effective if the General Assembly fails to enact a rate of return.

Contributions - All employees are required by State statute to contribute to the SCRS at the prevailing rate, currently 9.00 percent. The Authority contributed 16.41 percent of the total payroll for SCRS retirement. For 2021, the Authority also contributed an additional 0.15 percent of total payroll for group life.

Liabilities, Expense and Deferred Outflows (Inflows) of Resources Related to Pensions - At December 31, 2021, the Authority reported a liability of $294.5 million. This includes its share of the net pension liability from SCRS as well as pension liabilities associated with the supplemental executive retirement plans ("SERP") noted under post-employment benefits, which were immaterial. The SCRS net pension liability was measured as of June 30, 2021 and determined by an actuarial valuation as of July 1, 2020. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of $21.1 million paid to SCRS for the year ended June 30, 2021 relative to the actual contributions of $1.7 billion from all participating employers. The schedule of the Authority's proportionate share of the net pension liability for the years ended June 30, 2021 and 2020 are as follows:

	June 30, 2021	June 30, 2020
Authority's proportion of the net pension liability (%)	**1.28%**	1.28%
Authority's proportion of the net pension liability (millions)	**$ 278.9**	$ 327.9
Authority's covered employee payroll (millions)	**$ 152.7**	$ 149.7
Authority's proportion of the net pension liability as a percentage of its covered employee payroll	**183%**	219%
Plan fiduciary net position as a percentage of the total pension liability	**60.70%**	50.70%

For the year ended December 31, 2021, the Authority recognized a pension expense of $12.4 million, the Authority's proportionate share of the total pension expense. At December 31, 2021, the Authority reported deferred outflows (inflows) of resources related to pensions from the following sources:

	Deferred Outflows of Resources	**Deferred Inflows of Resources**
	(Thousands)	
Differences between expected and actual experience	**$ 4,776**	**$ 379**
Changes of assumptions	**15,293**	**0**
Net difference between projected and actual earnings on pension plan investments	**20,616**	**61,252**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**1,204**	**12,586**
Authority's contributions subsequent to the measurement date	**10,731**	**0**
Total	**$ 52,620**	**$ 74,217**

The Authority reported $10.7 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2022. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years. The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2021. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2020, was 3.91 years for SCRS.

Year Ending December 31:	
	(Thousands)
2022	**$ (9,432)**
2023	**(4,500)**
2024	**(3,193)**
2025	**(15,202)**
Total	**$ (35,327)**

For the year ended December 31, 2020, the Authority recognized a pension expense of $27.8 million, the Authority's proportionate share of the total pension expense. At December 31, 2020, the Authority reported deferred outflows (inflows) of resources related to pensions from the following sources:

	Deferred Outflows of Resources	**Deferred Inflows of Resources**
	(Thousands)	
Differences between expected and actual experience	**$ 3,803**	**$ 1,241**
Changes of assumptions	**424**	**0**
Net difference between projected and actual earnings on pension plan investments	**27,693**	**3,516**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**94**	**20,911**
Authority's contributions subsequent to the measurement date	**10,268**	**0**
Total	**$ 42,282**	**$ 25,668**

The Authority reported $10.3 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2021. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years. The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2020. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2019, was 3.984 years for SCRS.

Year Ending December 31:	
	(Thousands)
2021	$ (3,416)
2022	(663)
2023	4,266
2024	6,158
Total	$ 6,345

Actuarial Assumptions - Actuarial valuations of the Authority involve estimates of the reported amount and assumptions about probability of occurrence of events far into the future. Examples include assumptions about future employment mortality and future salary increases. Amounts determined regarding the net pension liability are subject to continual revision as actual results are compared with past expectations and new estimates are made about the future.

Significant actuarial assumptions and other inputs used to measure the total pension liability as of December 31, 2021:

- **Measurement Date**	**June 30, 2021**
- **Valuation Date**	**July 1, 2020**
- **Expected Return on Investments**	**7.25%**
- **Inflation**	**2.25%**
- **Future Salary Increases**	**3.00% to 12.50% (varies by service)**
- **Mortality Assumption**	**2016 Mortality Table set back projected at SCALE AA from year 2016 Males multiplied by 100%. Females multiplied by 111%**

Significant actuarial assumptions and other inputs used to measure the total pension liability as of December 31, 2020:

- Measurement Date	June 30, 2020
- Valuation Date	July 1, 2019
- Expected Return on Investments	7.25%
- Inflation	2.25%
- Future Salary Increases	3.00% to 12.50% (varies by service)
- Mortality Assumption	2016 Mortality Table set back projected at SCALE AA from year 2016 Males multiplied by 100%. Females multiplied by 111%

Discount Rate - The discount rate used to measure the total pension liability was 7.00 percent. The projection of cash flows used to determine the discount rate assumed that contributions from participating employers in SCRS will be made based on the actuarially determined rates based on provisions in the South Carolina State Code of Laws. Based on those assumptions, the fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Long-term Expected Rate of Return - For the measurement date as of June 30, 2021, the long-term expected rate of return on pension plan investments is based upon 20-year capital market assumptions. The long-term expected rates of return represent assumptions developed using an arithmetic building block approach primarily based on consensus expectations and market-based inputs. Expected returns are net of investment fees. The expected returns, along with the expected inflation rate, form the basis for the target allocation adopted at the beginning of the 2021 fiscal year. The long-term expected rate of return is produced by weighting the expected future real rates of return by the target allocation percentage and adding expected inflation and is summarized in the table on the following page. For actuarial purposes, the 7.00 percent assumed annual investment rate of return (as prescribed by South Carolina Code Section 9-16-335) used in the calculation of the total pension liability includes a 4.75 percent real rate of return and a 2.25 percent inflation component.

Asset Class	Target Asset Allocation	Expected Arithmetic Real Rate of Return	Long-Term Expected Portfolio Real Rate of Return
Global Equity			
Public Equity	**46.00%**	**6.87%**	**3.16%**
Private Equity	**9.00%**	**9.68%**	**0.87%**
Real Assets			
Real Estate	**9.00%**	**6.01%**	**0.54%**
Infrastructure	**3.00%**	**5.08%**	**0.15%**
Diversified Credit			
Bonds	**26.00%**	**0.27%**	**0.07%**
Private Debt	**7.00%**	**5.47%**	**0.39%**
Total Expected Real Return	**100.0%**		**5.18%**
Inflation for Actuarial Purposes			**2.25%**
Total Expected Nominal Return			**7.43%**

For the measurement date as of June 30, 2020, the long-term expected rate of return on pension plan investments is based upon 20-year capital market assumptions. The long-term expected rates of return represent assumptions developed using an arithmetic building block approach primarily based on consensus expectations and market-based inputs. Expected returns are net of investment fees. The expected returns, along with the expected inflation rate, form the basis for the target allocation adopted at the beginning of the 2020 fiscal year. The long-term expected rate of return is produced by weighting the expected future real rates of return by the target allocation percentage and adding expected inflation and is summarized in the table on the following page. For actuarial purposes, the 7.25 percent assumed annual investment rate of return (as prescribed by South Carolina Code Section 9-16-335) used in the calculation of the total pension liability includes a 5.00 percent real rate of return and a 2.25 percent inflation component.

Asset Class	**Target Asset Allocation**	**Expected Arithmetic Real Rate of Return**	**Long-Term Expected Portfolio Real Rate of Return**
Global Equity			
Global Public Equity	**35.00%**	**7.81%**	**2.73%**
Private Equity	**9.00%**	**8.91%**	**0.80%**
Equity Options Strategies	**7.00%**	**5.09%**	**0.36%**
Real Assets			
Real Estate (Private)	**8.00%**	**5.55%**	**0.44%**
Real Estate (REITs)	**1.00%**	**7.78%**	**0.08%**
Infrastructure (Private)	**2.00%**	**4.88%**	**0.10%**
Infrastructure (Public)	**1.00%**	**7.05%**	**0.07%**
Opportunistic			
GTAA/Risk Parity	**7.00%**	**3.56%**	**0.25%**
Other Opportunistic Strategies	**1.00%**	**4.41%**	**0.04%**
Diversified Credit			
High Yield Bonds/ Bank Loans	**4.00%**	**4.21%**	**0.17%**
Emerging Markets Debt	**4.00%**	**3.44%**	**0.14%**
Private Debt	**7.00%**	**5.79%**	**0.40%**
Conservative Fixed Income			
Core Fixed Income	**13.00%**	**1.60%**	**0.21%**
Cash and Short Duration (Net)	**1.00%**	**0.56%**	**0.01%**
Total Expected Real Return	**100.0%**		**5.80%**
Inflation for Actuarial Purposes			**2.25%**
Total Expected Nominal Return			**8.05%**

Sensitivity Analysis - For the measurement date as of June 30, 2021, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.00% as well as SERP discount rates of 2.25% for both the pre-2007 and non-qualified benefits for what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current rate.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(Thousands)	
Authority's proportionate share of the net pension liability	**$ 382,002**	**$ 294,504**	**$ 221,685**

For the measurement date as of June 30, 2020, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.25% as well as SERP discount rates of 2.00% for both the pre-2007 and non-qualified benefits for what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current rate.

	1.00% Decrease	Current Discount Rate	1.00% Increase
		(Thousands)	
Authority's proportionate share of the net pension liability	$ 424,440	$ 344,795	$ 278,203

Other Retirement Benefits - The Authority also provides retirement benefits to certain employees designated by management and the Board under SERP. Benefits are established and may be amended by management and the Authority's Board and include retirement benefit payments for a specified number of years and death benefits. The cost of these benefits is actuarially determined annually. Beginning in 2006, these plans were segregated into internal and external funds. The qualified benefits are funded externally with the annual cost set aside in a trust administered by a third party. The pre-2007 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. Effective February 23, 2018, entry into the plan is closed and no employee shall become a participant on or after this date. At December 31, 2021, the Authority reported an asset of $4.7 million and a liability of $15.5 million associated with the three plans as well as deferred outflows and inflows as follows:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ 23	$ 374
Changes of assumptions	14	3
Net difference between projected and actual earnings on pension plan investments	165	931
Authority's contributions subsequent to the measurement date	188	0
Total	**$ 390**	**$ 1,308**

The Authority reported $188,000 as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2022. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years.

The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2021.

Year Ending December 31:	
	(Thousands)
2022	**$ (414)**
2023	**(343)**
2024	**(202)**
2025	**(146)**
2026	**0**
Total	**$ (1,105)**

At December 31, 2020, the Authority reported an asset of $3.9 million and a liability of $16.9 million associated with the three plans as well as deferred outflows and inflows as follows:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ 280	$ 682
Changes of assumptions	120	10
Net difference between projected and actual earnings on pension plan investments	330	644
Authority's contributions subsequent to the measurement date	187	0
Total	$ 917	$ 1,336

The Authority reported $187,000 as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2021. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years.

The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2020.

Year Ending December 31:		
		(Thousands)
2021	$	(58)
2022		(279)
2023		(207)
2024		(61)
2025		0
Total	$	(605)

Summer Nuclear Unit 1 Retirement - The Authority and Dominion Energy, Inc. are parties to a joint ownership agreement for Summer Nuclear Unit 1 at the Summer Nuclear Station. As such, the Authority is responsible for funding its share of pension requirements for the nuclear station personnel. Any earnings generated from the established pension plan are shared proportionately and used to reduce the allocated funding.

As of December 31, 2021, and 2020, the Authority had a pension liability of $8.1 million and $9.1 million, respectively.

In accordance with FASB ASC 715, the Authority has a regulatory asset balance of approximately $9.2 million and $9.7 million for the unfunded portion of pension benefits at December 31, 2021 and 2020, respectively. Additional information may be obtained by reference to the Dominion Energy Inc. Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2021.

Note 12 – Other Postemployment Benefits (OPEB)

Vacation / Sick Leave - Full-time employees earn 10 days of vacation leave for service under five years and 15 days of vacation leave for service under 11 years. Employees earn an additional day of vacation leave for each year of service over 10 until they reach the maximum of 25 days per year. Employees earn two hours per pay period, plus 20 additional hours at year-end for sick leave.

Employees may accumulate up to 45 days of vacation leave and 180 days of sick leave. Upon termination, the Authority pays employees for unused vacation leave at the pay rate then in effect. In addition, the Authority pays employees upon retirement 20 percent of their sick leave at the pay rate then in effect.

Plan Description - The Authority participates in an agent multiple-employer defined benefit healthcare plan whereby PEBA Insurance Benefits provides certain health, dental and life insurance benefits for eligible retired employees of the Authority. The retirement insurance benefits available are defined by PEBA Insurance Benefits and substantially all of the Authority's employees may become eligible for these benefits if they meet retirement eligibility with a minimum of 10 years of earned service or upon reaching age 60 after leaving employment with at least 20 years of service. Currently, approximately 1,100 retirees meet these requirements.

For employees hired May 2, 2008 or thereafter, the number of years of earned service necessary to qualify for funded retiree insurance is 15 years for a one-half contribution, and 25 years for a full contribution. PEBA Insurance Benefits may be contacted at: PO Box 11661, Columbia, S.C. 29211-1661 and PEBA Retirement Benefits may be contacted at PO Box 11660, Columbia, S.C. 29211-1960.

As of the measurement date, June 30, 2021, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	1,124
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	-
Active Plan Members	1,591
Total Plan Members	**2,715**

As of the measurement date, June 30, 2020, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	1,107
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	-
Active Plan Members	1,623
Total Plan Members	**2,730**

Funding Policy - Prior to 2010, the Authority used the unfunded pay-as-you-go option (or cash disbursement) method pursuant to GASB 45 to record the net OPEB obligations. During 2010, the Authority elected to adopt an advanced or pre-funding policy and established an irrevocable trust with Synovus Trust Company. In 2018 with the implementation of GASB 75, the Authority established a formal funding plan and elected to fund the OPEB obligation over a 30-year closed period. This method of funding will result in a lower OPEB liability and establishes a method for amortizing the regulatory asset as funding occurs.

Net OPEB Liability - The components of the net OPEB liability at June 30, 2021 were as follows:

	(Thousands)
Total OPEB Liability	$ 293,309
Plan fiduciary net position	105,781
Authority's net OPEB liability	$ 187,528
Plan fiduciary net position as a percentage of the total OPEB liability	36.06%

The components of the net OPEB liability at June 30, 2020 were as follows:

	(Thousands)
Total OPEB Liability	$ 274,983
Plan fiduciary net position	98,874
Authority's net OPEB liability	$ 176,109
Plan fiduciary net position as a percentage of the total OPEB liability	35.96%

Actuarial Methods and Assumptions - The total OPEB liability was determined by an actuarial valuation as of June 30, 2020 using the following actuarial assumptions, applied to all periods included in the measurement, unless otherwise specified.

Actuarial Methods and Assumptions	
Actuarial Cost Method	Individual Entry-Age
Amortization Method	Level dollar
Amortization Period	Closed period; 26 years remaining as of the beginning of FYE21
Asset Valuation	Market Value
Investment Rate of Return	3.50%, net of investment expenses, including inflation
Inflation	2.25%
Salary Increases	3.00% to 7.00%, including inflation
Demographic Assumptions	Based on the experience study covering the five year period ending June 30, 2015 as conducted for the South Carolina Retirement Systems (SCRS)
Mortality	For healthy retirees, the 2016 Public Retirees of South Carolina Mortality Table for Males and the 2016 Public Retirees of South Carolina Mortality Table for Females are used with fully generational mortality projections based on Scale AA from the year 2016. The following multipliers are applied to the base tables: 100% for male SCRS members, 111% for female SCRS members.
Participation Rates	Rates of 95% for fully funded retirees, 60% for partially funded retirees, and 20% for retirees not eligible for any explicit subsidy.
Healthcare Cost Trend Rates	Initial rate of 6.40% declining to an ultimate rate of 4.15% after 15 years

Investments - The investments of the Authority must follow the general guidelines set by the Enabling Legislation. The Authority is required to invest without limitation its revenues in obligations the interest and principal of which are guaranteed or are fully secured by contracts with the United States of America; in obligations of any agency, instrumentality or corporation which has been or may hereafter be created by or pursuant to an act of Congress; direct and general obligations of the State of South Carolina; and certificates of deposit issued by any bank, trust company or national banking association which do business in South Carolina.

Asset Class	**Target Allocation**	**Long-Term Expected Real Rate of Return**
Cash	.13%	0.1%
Fixed Income	99.87%	2.6%
Total Blended Average	**100.0%**	**2.5%**

Asset Allocation at June 30, 2021

The rate of return for 2021 on the Trust was (2.00)%.

Discount rate. A Single Discount Rate of 3.00% was used to measure the total OPEB liability. The expected rate of return on OPEB plan investments is 3.00%. The municipal bond rate is 1.92% (based on the daily rate closest to but not later than the measurement date of the Fidelity "20-Year Municipal GO AA Index"); and the resulting Single Discount Rate is 3.00%.

Schedule of Changes in Net OPEB Liability and Related Ratios
Fiscal Year Ended December 31, 2021

Measurement period ending June 30		**2021**		2020
		(Thousands)		
Service Cost	**$**	**6,899**	$	6,821
Interest on the total OPEB liability		**9,573**		9,425
Difference between expected and actual experience		**7,692**		242
Changes of Assumptions		**3,975**		(2,717)
Benefit payments		**(9,813)**		(9,351)
Net change in total OPEB liability		**18,326**		4,420
Total OPEB liability - beginning		**274,983**		270,563
Total OPEB liability - ending (a)	**$**	**293,309**	$	274,983
Plan fiduciary net position				
Employer contributions	**$**	**18,573**	$	18,812
OPEB plan net investment income		**(1,686)**		5,717
Benefit payments		**(9,813)**		(9,351)
OPEB plan administrative expense		**(167)**		(153)
Net change in plan fiduciary net position		**6,907**		15,025
Plan fiduciary net position - beginning		**98,874**		83,849
Plan fiduciary net position - ending (b)	**$**	**105,781**	$	98,874
Net OPEB liability - ending (a) - (b)	**$**	**187,528**	$	176,109
Plan fiduciary net position as a percentage of total OPEB liability		**36.06%**		35.96 %
Covered-employee payroll (dollars)	**$**	**148,938,030**	$	149,128,347
Net OPEB liability as a percentage of covered-employee payroll		**125.91 %**		118.09 %

Sensitivity of the net OPEB liability to changes in the discount rate - The following presents the net OPEB liability of the Authority calculated using the Authority's discount rate of 3.00% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate as of June 30, 2021.

	1.00% Decrease	Current Discount Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 237,421	$ 187,528	$ 147,524

The following presents the net OPEB liability of the Authority calculated using the Authority's discount rate of 3.50% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate as of June 30, 2020.

	1.00% Decrease	Current Discount Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 221,141	$ 176,109	$ 139,752

Sensitivity of the net OPEB liability to changes in the healthcare cost trend rates - The following presents the net OPEB liability of the Authority calculated using the Authority's healthcare cost trend rate of 7.00% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate as of June 30, 2021.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 139,900	$ 187,528	$ 249,196

The following presents the net OPEB liability of the Authority calculated using the Authority's healthcare cost trend rate of 7.00% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate as of June 30, 2020.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 130,414	$ 176,109	$ 235,077

OPEB Expense and Deferred Outflows (Inflows) of Resources Related to OPEB - For the year ended December 31, 2021, the Authority recognized OPEB expense of $19.5 million. At December 31, 2021, the Authority reported deferred outflows (inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ **6,751**	$ **7,450**
Changes of assumptions	**28,833**	**1,938**
Net difference between projected and actual earnings on OPEB plan investments	**2,242**	**0**
Authority's contributions subsequent to the measurement date	**11,264**	**0**
Total	$ **49,090**	$ **9,388**

The Authority reported $11.3 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net OPEB liability in the year ending December 31, 2022. Other amounts reported as deferred outflows (inflows) of resources will be recognized in OPEB expense in future years.

The following schedule reflects the amortization of the Authority's balance of remaining deferred outflows (inflows) of resources at December 31, 2021.

Year Ending December 31:	(Thousands)
2022	$ 6,441
2023	5,908
2024	6,387
2025	6,827
2026	1,344
Thereafter,	1,531
Total	$ 28,438

For the year ended December 21, 2020, the Authority recognized OPEB expense of $17 million. At December 31, 2020, the Authority reported deferred outflows (inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	**Deferred Inflows of Resources**
	(Thousands)	
Differences between expected and actual experience	**$ 207**	**$ 9,336**
Changes of assumptions	**31,836**	**2,327**
Net difference between projected and actual earnings on OPEB plan investments	**0**	**2,464**
Authority's contributions subsequent to the measurement date	**10,233**	**0**
Total	**$ 42,276**	**$ 14,129**

The Authority reported $10.2 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net OPEB liability in the year ending December 31, 2021. Other amounts reported as deferred outflows (inflows) of resources will be recognized in OPEB expense in future years.

The following schedule reflects the amortization of the Authority's balance of remaining deferred outflows (inflows) of resources at December 31, 2020.

Year Ending December 31:	(Thousands)
2021	$ 3,692
2022	3,692
2023	3,160
2024	3,639
2025	4,078
Thereafter,	(344)
Total	$ 17,915

Summer Nuclear OPEB - The Authority is responsible for funding its share of OPEB costs for nuclear station employees. The Authority's liability balances as of December 31, 2021 and 2020 were both approximately $12.4 million and $11.9 million, respectively.

In accordance with FASB ASC 715, the Authority recorded a regulatory asset of approximately $600,000 for the unfunded portion of OPEB costs at December 31, 2021 and 2020. Additional information may be obtained by reference to the Dominion Energy, Inc. Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2021.

Note 13 – Credit Risk and Major Customers

In 2021, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:		2021		2020
		(Millions)		
Central	**$**	**1,003**	$	968

The Authority maintains an allowance for uncollectible accounts based upon the expected collectability of all accounts receivable. The allowance at each year ended December 31, 2021 and 2020 was $2.6 million and $2.4 million, respectively.

Note 14 – Impact of Novel Coronavirus (COVID-19) Pandemic

In March 2020, a Presidential Declaration of Disaster was issued for the Federal Reimbursement of Protective Measure costs incurred from the COVID-19 Pandemic through FEMA Public Assistance Program. Protective Measure costs are defined as those that are directly related to accomplishing the specified emergency health and safety measures to ensure the Authority maintains a safe environment for its employees and customers. FEMA Public Assistance Program guidelines provide these Protective Measure costs must be directly related to the event and would not be incurred if not for the event.

The Authority will continue to collect Protective Measures costs associated with the COVID-19 pandemic until the end of the incident period based upon the Declaration of Disaster guidelines which has been extended into 2022. Federal Reimbursement for the COVID-19 Protective Measure Expenses is anticipated in 2022 and 2023.

The Authority captured all costs associated with the Protective Measures incurred in 2021 and 2020. The amounts were approximately $13.7 million and $3.5 million, respectively. The Authority recorded a $4.3 million receivable for the anticipation of reimbursement of a portion of the Protective Measure Cost incurred during 2020, which was subsequently reversed in December 2021. The Authority reversed the receivable due to limited and changing FEMA guidelines for eligibility of costs. The Authority continues to monitor the COVID-19 Pandemic and all costs associated with the global event for any financial impact but does not expect the costs associated with this event to have measurable long-term impact on its operations of the production and delivery of electricity to its customers.

The Authority continues to take proactive steps to help customers adversely affected by COVID-19 by working with customers and offering payment arrangement options. While the number of delinquent accounts had increased during the early stages of the pandemic, since mid-July 2020 daily delinquency numbers and balances for the Authority's residential and commercial customers have returned to pre-COVID levels. As of December 31, 2021, the Authority had 20 delinquent residential and commercial accounts pending disconnect with an aggregate balance of less than approximately $10,000.

Note 15 – Cook Settlement as to Rates

On July 31, 2020, the Board authorized management to implement the terms of the Cook Settlement Agreement reached with plaintiff's counsel in settlement of the Cook Case. The Cook Settlement Agreement provides, in part, for "Settlement Rate(s)" described below effective as follows: (i) for the customers other than Central whose rates are subject to the rate lock, effective for all bills rendered on or after August 16, 2020 through all bills rendered on or before January 15, 2025, and (ii) for Central, effective for service rendered on or after August 1, 2020, through service rendered on or before December 31, 2024. The period from August 1, 2020 through January 15, 2025 is referred to as the "Settlement Rate Period."

In accordance with the terms of the Cook Settlement Agreement, the Board has authorized management to lock the rate schedules and suspend the existing variable rate components of select rates and replace them with those established in the Cook Settlement Agreement during the Settlement Rate Period. The Settlement Rates impact a vast majority of the Authority's customers and locks the majority of Central's rate components to those established in Schedule A of the Cook Settlement Agreement and most variable rate components for the majority of the Authority's non-Central customers to those projected in Schedule B of the Cook Settlement Agreement. The Settlement Rate suspends the operations of the fuel adjustment, demand sales adjustment and economic development sales adjustment for customers with rate codes designated on Schedule B of the Cook Settlement Agreement. This results in rates being locked for almost all residential and commercial customers participating in the Settlement Rate, as well as industrial customers served under the Schedule L rate and the Interruptible and Economy Power Optional riders. The Settlement Rate under Schedule B also applies to customers with contractual rates based on the Municipal Street Lighting rate (ML), the cities of Bamberg, Georgetown and Seneca. The rate lock agreed to in the Cook Settlement Agreement is consistent with rates and the rate stabilization period projected in the Authority's Act 95 Reform Plan.

Consistent with being a rate lock, the Authority has agreed in the Cook Settlement Agreement not to defer any costs and expenses incurred or otherwise appropriately attributable to any year during the Settlement Rate Period to any other year or years during or after the Settlement Rate Period, except that the Authority may defer to rates charged in years after the Settlement Rate Period just and reasonable costs and expenses incurred during the Settlement Rate Period directly resulting from the following circumstances: (a) a change in law (not initiated or advocated for by the Authority); (b) named storm events, acts of God or the public enemy, flood, fire, strike, or catastrophic failure of equipment for reasons beyond the Authority's control; (c) significant cyber security attacks or other security attacks outside of the Authority's control; (d) changes in regulatory or governance requirements imposed by the Act 95 legislative process, (e) certain deviations in Central's actual loads (used for allocation of demand costs) as compared to Central's billing determinants used in the Authority's Act 95 Reform Plan, and (f) if the Authority's costs incurred are increased above those in the Authority's Act 95 Reform Plan because the Authority is not permitted to engage in forward hedging of fuel price solely by reason of restrictions imposed by the Act 95 legislative process and solely for the period of such restrictions imposed by the Act 95 legislative process.

The Authority currently expects that projected Revenues using the Settlement Rates described herein will be sufficient to the meet the obligations of the Authority under the Revenue Obligations Resolution. To date, the Board has not approved any related deferrals.

Note 16 – Subsequent Events

Tender and Exchange - On February 23, 2022 Santee Cooper closed on the 2022AB tender and exchange transaction which resulted in:

1) selling approximately $931.0 million of 2022 Tax-Exempt Refunding Series A to purchase bonds tendered by investors (purchase from investors $943.0 million of outstanding high-coupon bonds), and

2) exchanging with investors approximately $352.0 million of 2022 Tax-Exempt Refunding Series B for their outstanding high-coupon bonds.

The combination of the 2022A Bonds and the 2022B Bonds will mature in years 2023 – 2055.

Santee Cooper offered to purchase or exchange $2.697 billion in callable bonds for this 2022AB transaction. Santee Cooper received $1.287 billion of combined investor offers – all of which were accepted, for a 47.74% participation rate.

The All-In TIC for this transaction is 3.31% and the refunding produced approximately $378.0 million in gross savings which results in approximately $250.0 million in net present value debt service savings. Savings produced by this transaction will be levelized and this transaction will not increase par or extend the life of the debt. Santee Cooper and Bond Counsel have reviewed the transaction and confirm that it was executed within the parameters approved by the Joint Bond Review Committee.

The Southeast Energy Exchange Market (SEEM) – Effective January 4, 2022, Santee Cooper joined SEEM. SEEM is a unique and new approach to enhancing the existing bilateral market. The new SEEM platform will facilitate sub-hourly, bilateral trading, allowing participants to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission. Participation in SEEM is open to other entities that meet the appropriate requirements. SEEM is designed to keep pace with the changes resulting from the electricity sector growing toward an ever-greener future. Southeastern electricity customers are expected see cost and environmental benefits as a result of the new platform.

Other founding members of SEEM are expected to include Associated Electric Cooperative, Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, N.C. Municipal Power Agency No. 1, NCEMC, Oglethorpe Power Corp., PowerSouth, Southern Company and TVA.

The founding members represent nearly 20 entities in 11 states with more than 160,000 MWs (summer capacity; winter capacity is nearly 180,000 MWs) across two time zones. These companies serve the energy needs of more than 32 million retail customers (roughly more than 50 million people).

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REQUIRED SUPPLEMENTAL FINANCIAL DATA:

Santee Cooper's Proportionate Share of the Net Pension Liability
Required Supplementary Information

Years Ended in June 30,	**2021**	2020	2019	2018	2017	2016	2015	2014
Authority's proportion of the net pension liability (%)	**1.28%**	1.28%	1.35%	1.43%	1.43%	1.45%	1.44%	1.45%
Authority's proportion of the net pension liability (millions)	**$278.9**	$327.9	$309.7	$321.8	$323.1	$309.7	$273.6	$249.7
Authority's covered payroll (millions)	**$152.7**	$149.7	$151.1	$156.5	$153.7	$147.7	$140.7	$135.0
Authority's proportion of the net pension liability as a percentage of its covered payroll	**183%**	219%	205%	206%	210%	210%	194%	184%
Plan fiduciary net position as a percentage of the total pension liability	**60.7%**	50.7%	54.4%	54.1%	53.3%	56.9%	59.9%	59.9%

[1] Information is not available for years prior to 2014.

Santee Cooper Pension Plan Contribution
Required Supplementary Information

Years Ended December 31,	2021	2020	2019	2018	2017	2016	2015	2014
				(Millions)				
Required Contributions:								
From the Authority	**$ 22.1**	$ 22.1	$ 20.6	$ 19.8	$ 17.7	$ 15.6	$ 14.8	$ 13.9
From employees	**12.5**	12.9	12.4	12.8	12.6	11.8	11	10.2
Contributions in relation to the required contributions:								
From the Authority	**$22.1**	$ 22.1	$ 20.6	$ 19.8	$ 17.7	$ 15.6	$ 14.8	$ 13.9
From employees	**12.5**	12.9	12.4	12.8	12.6	11.8	11	10.2
Contribution deficiency (excess)	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Authority's covered payroll	**138.3**	143.6	138.2	142.3	142.7	140.1	136.4	131.5
Authority's contributions as a percentage of covered payroll	**16.00%**	15.40%	14.90%	13.90%	12.40%	11.10%	10.90%	10.50%

[1] Information is not available for years prior to 2014.

Schedule of Changes in Net OPEB Liability and Related Ratios

Measurement period ending June 30	**2021**	2020	2019	2018
	(Thousands)			
Service Cost	**$ 6,899**	$ 6,821	$ 4,641	$ 5,405
Interest on the total OPEB liability	**9,573**	9,425	10,375	10,073
Difference between expected and actual experience	**7,692**	242	(12,859)	(291)
Changes of Assumptions	**3,975**	(2,717)	44,641	0
Benefit payments	**(9,813)**	(9,351)	(8,937)	(7,253)
Net change in total OPEB liability	**18,326**	4,420	37,861	7,934
Total OPEB liability - beginning	**274,983**	270,563	232,702	224,768
Total OPEB liability - ending (a)	**$ 293,309**	$ 274,983	$ 270,563	$ 232,702
Plan fiduciary net position				
Employer contributions	**$ 18,573**	$ 18,812	$ 27,483	$ 14,455
OPEB plan net investment income	**(1,686)**	5,717	5,501	(120)
Benefit payments	**(9,813)**	(9,351)	(8,937)	(7,253)
OPEB plan administrative expense	**(167)**	(153)	(126)	(104)
Net change in plan fiduciary net position	**6,907**	15,025	23,920	6,978
Plan fiduciary net position - beginning	**98,874**	83,849	59,928	52,950
Plan fiduciary net position - ending (b)	**$ 105,781**	$ 98,874	$ 83,849	$ 59,928
Net OPEB liability - ending (a) - (b)	**$ 187,528**	$ 176,109	$ 186,714	$ 172,774
Plan fiduciary net position as a percentage of total OPEB liability	**36.06%**	35.96%	30.99%	25.75%
Covered-employee payroll	**$148,938,030**	$149,128,347	$149,862,640	156,058,022
Net OPEB liability as a percentage of covered-employee payroll	**125.91%**	118.09%	124.59%	110.71%

[1] Information is not available for years prior to 2018.

Schedule of Contributions
(Thousands)

For December	Actuarially Determined Contribution	Actual Contribution	Contribution Deficiency (Excess)	Covered Payroll	Actual as a % of Covered Payroll
2021	**$ 18,224**	**$ 19,606**	**$ (1,382)**	**$ 149,053**	**13.15%**
2020	$ 18,012	$ 18,898	$ (886)	$ 155,676	12.14%
2019	$ 15,515	$ 17,262	$ (1,747)	$ 154,791	11.15%
2018	$ 15,364	$ 14,455	$ 909	$ 156,059	9.26%

Notes to Schedule:
Changes of assumptions: Changes of assumptions and other inputs reflect the effects of changes in the discount rate of each period. The following is the discount rate used in this period:

Fiscal Year Ending	Rate
2021	**3.00%**
2020	3.50%
2019	3.50%
2018	4.50%

Schedule of Investment Returns

Year ended June 30, 2021

	2021	2020	2019	2018
Annual money-weighted rate of return, net of investment expenses	**(1.63)%**	6.46%	7.96%	(0.21)%

[1] Information is not available for years prior to 2018.

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Board of Directors

Peter M. McCoy Jr.
Chairman
Charleston, South Carolina

Chairman McCoy is an attorney and the sole proprietor of McCoy Law Group LLC, a firm located in Charleston, and a former U.S. Attorney for the District of South Carolina.

Dan J. Ray
1st Vice Chairman
Georgetown County
Georgetown, S.C.

Director Ray is president of DR Capital Group, a Pawleys Island-based financial advisory and investment company.

David F. Singleton
2nd Vice Chairman
Horry County
Myrtle Beach, S.C.

Director Singleton is president of Singleton Properties, a real estate investment and sales firm.

Kristofer D. Clark
3rd Congressional District
Easley, S.C.

Director Clark is a broker with Easlan Capital and owner of Pristine Properties LLC.

William A. Finn
1st Congressional District
Mount Pleasant, S.C.

Director Finn is a retired chairman of AstenJohnson Inc., a specialty textile company for the printing and papermaking industries based in Charleston.

Merrell W. Floyd
7th Congressional District
Conway, S.C.

Director Floyd is a retired staff coordinator for Horry Electric Cooperative.

J. Calhoun Land IV
6th Congressional District
Manning, S.C.

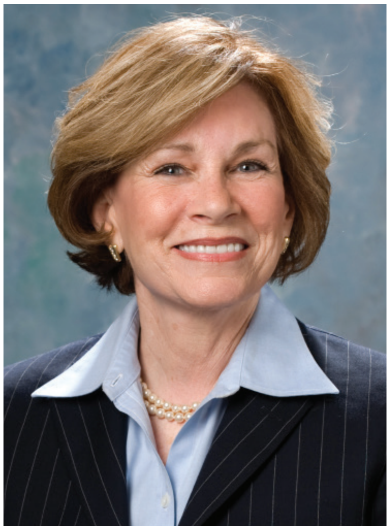
Director Land is a partner in Land, Parker & Welch, a general practice firm in Manning.

Charles H. "Herb" Leaird
5th Congressional District
Sumter, S.C.

Director Leaird is the former CEO of Black River Electric Cooperative and also served as CEO of Lynches River Electric Cooperative.

Stephen H. Mudge
At-Large
Clemson, S.C.

Director Mudge is the cofounder, president and CEO of Serrus Capital Partners Inc., a Greenville, S.C.-based real estate investment firm.



Peggy H. Pinnell
Berkeley County
Moncks Corner, S.C.

Director Pinnell is the owner of the Peggy H. Pinnell Insurance Agency in Moncks Corner, a State Farm agency.

Barry D. Wynn
4th Congressional District
Spartanburg, S.C.

Director Wynn is president of Colonial Trust Company, a private trust company specializing in investment management and estate services.

Advisory Board

Henry D. McMaster	Governor
Alan Wilson	Attorney General
Mark Hammond	Secretary of State
Richard Eckstrom	Comptroller General
Curtis M. Loftis Jr.	State Treasurer

Leadership

Mark B. Bonsall	President and Chief Executive Officer
Charlie B. Duckworth	Deputy CEO and Chief of Planning and Innovation Officer
Thomas B. Curtis	Chief Generation Officer
Kenneth W. Lott III	Chief Financial and Administration Officer
J. Michael Poston	Chief Customer Officer
Monique L. Washington	Chief Audit and Risk Officer
Pamela J. Williams	Chief Public Affairs Officer and General Counsel

Other Officers

Michael O. Frederick	Chief of Law Enforcement and Security
B. Shawan Gillians	Director of Legal Services and Corporate Secretary
Dominick G. Maddalone	Senior Director of Innovation and Chief Information Officer
Daniel T. Manes	Controller
Suzanne H. Ritter	Treasurer

Notes:

Mark B. Bonsall returned to retirement and his last day at Santee Cooper was Jan. 7, 2022. The Board of Directors named Charlie B. Duckworth as Acting President and CEO for the time period of Jan. 8, 2022, to Feb. 28, 2022, and hired Jimmy D. Staton as President and CEO as of March 1, 2022.

On Oct. 22, 2021, Monique L. Washington's title was changed from Chief Audit Executive to Chief Audit and Risk Officer.

On Nov. 1, 2021, Generation and Fuel operations was combined into one unit and J. Martine "Marty" Watson was named Interim Power Supply Officer and Thomas B. Curtis was named Senior Manager of Transmission Technical Operations. The Board of Directors confirmed Watson as the Chief Power Supply Officer on Dec. 6, 2021.

Office Locations

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