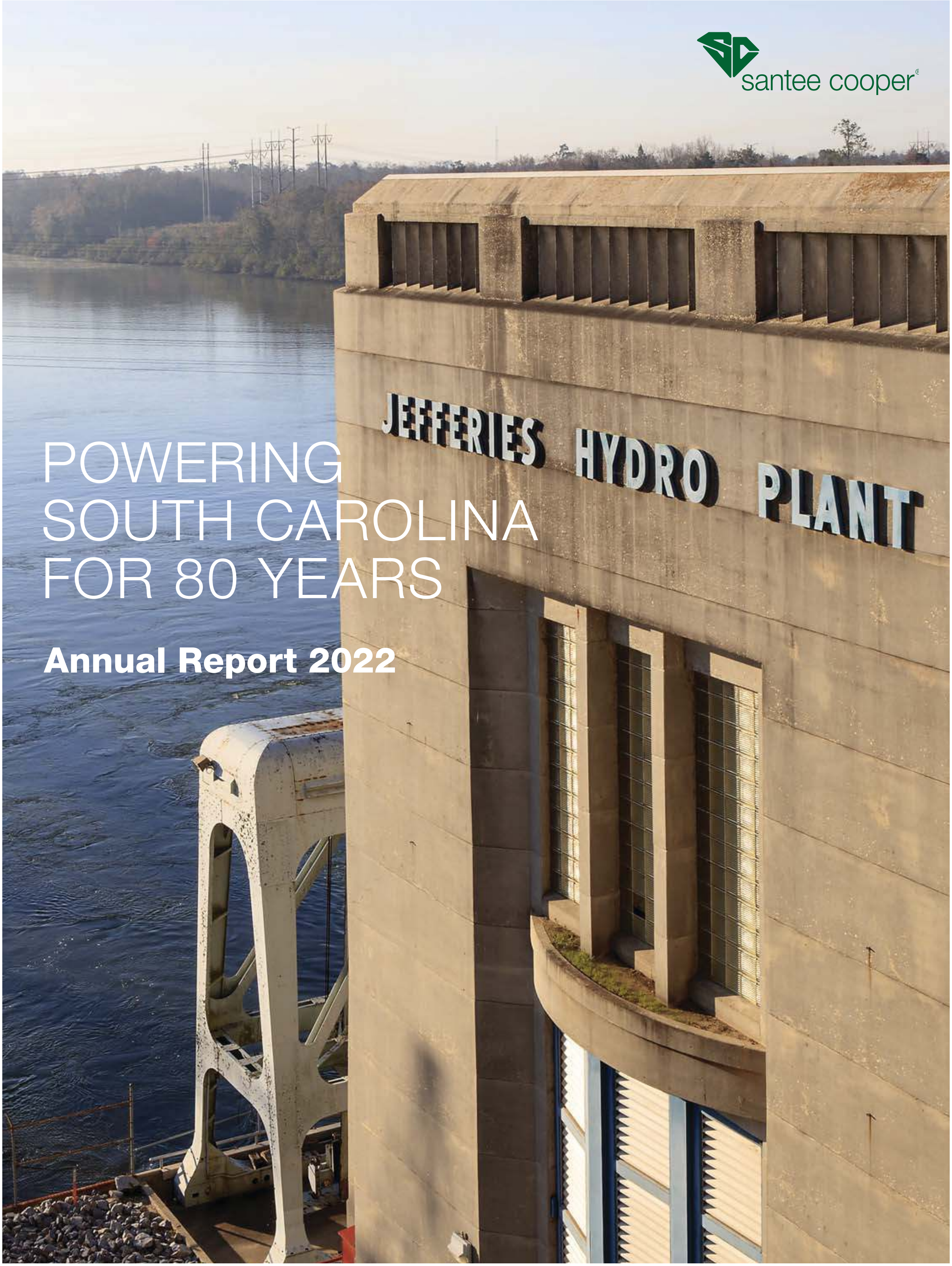
santee cooper

POWERING SOUTH CAROLINA FOR 80 YEARS

Annual Report 2022



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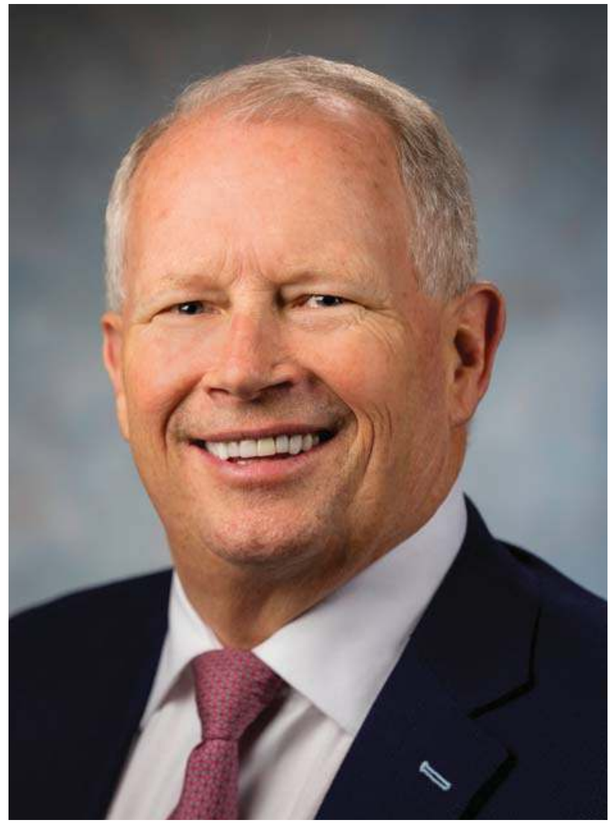
Letter from the Chairman and CEO



The year 2022 marked the 80th anniversary of Jefferies Hydroelectric Station, which came online Feb. 17, 1942, and continues to provide clean hydropower today. It was Santee Cooper's first generating station.

Construction began in 1939. Just two years later, President Roosevelt designated the then-named Pinopolis Power Plant a national defense project, accelerating its construction as America joined World War II. The hydro plant was later renamed for former Santee Cooper General Manager and South Carolina Gov. Richard M. Jefferies.

Its first customer was Pittsburgh Metallurgical Co., a defense contractor in North Charleston that made metal used to harden ships and tanks. Over the years, Santee Cooper powered the Charleston Naval Shipyard and the Charleston Naval Base, and today still serves Joint Base Charleston.

Along with the war effort, Santee Cooper supported the people of South Carolina.

The Santee Cooper Project became the nation's biggest land-clearing effort and the largest federal Works Progress Administration project east of the Mississippi River during the New Deal. More than 12,500 workers toiled for 27 months, clearing swamps and woodlands, building dams and dikes, and constructing a powerhouse and navigation lock. The navigation lock at the Pinopolis Dam was itself a monumental construction. Featuring a 75-foot drop from Lake Moultrie to the Tailrace Canal, it was the tallest single-lift lock in the world at the time.

The Santee Cooper Project was, and remains, one of South Carolina's most resource-laden assets, an important source of energy, jobs and industrial development. Considered an engineering feat in its day, it drew more than 65,000 people from all over the country who visited the site to marvel at its progress. Nationally syndicated cartoonists penned tributes to its completion and its importance.

Today, the hydro units remain an important source of capacity. The units are also important to integrating intermittent renewables because they can be brought online in a matter of minutes. And there's this: 80 years after it came online, Jefferies Hydro remains Santee Cooper's most economical energy source.

2022 In Review

Despite widespread industry challenges due to staggering inflation and continued supply chain issues, Santee Cooper achieved many accomplishments in 2022.

> **Planning for Future Energy Needs**: We advanced work necessary to ensure Santee Cooper continues to power South Carolina and energize homes and businesses – both our current customers and those coming in the future. We made significant progress on analysis and public input related to Santee Cooper's first triennial Integrated Resource Plan, to be filed with the South Carolina Public Service Commission in May 2023. We are working with other utilities to optimize our capabilities: Santee Cooper is a founding member of the Southeast Energy Exchange Market (SEEM). SEEM is a market established by the signatories of the Southeastern Energy Exchange Market Agreement of December 28, 2020, as amended. The signatories to that organic agreement are called Members and the market created by this organic agreement is governed by a Membership Board, which launched in November and allows participants to buy and sell energy close to the time it is consumed, saving customers money and helping integrate renewables across the SEEM platform. Santee Cooper is also exploring options to build new generation jointly with other utilities, seeking economies of scale and other benefits. We have also begun a just transition process to maximize opportunities for the Georgetown community upon the requirement of the Winyah Generating Station.

> **Providing Essential Drinking Water**: Our regional water systems continued to hydrate consumers across the eastern part of South Carolina, adding transmission reaches and storage tanks to meet growth in existing service territories and to deliver safe drinking water to new areas. The Lake Moultrie system serves more than 220,000 consumers across the Lowcountry and is growing. The Lake Marion Regional Water System's five-year plan calls for aggressive system growth, with the expected addition of seven new reaches and two elevated water tanks.

> **Powering Electric Vehicles**: We launched innovative customer-facing technologies and programs, such as grants to help commercial customers improve electric vehicle (EV) infrastructure and deeply discounted rates to help residential customers charge EVs. The new rates reward customers who charge their vehicles overnight, when energy demand is lowest, which helps reduce the need for additional utility-built generation as more EVs come into the market. Santee Cooper also offers rebates for residential customers who install EV chargers.

> **Enabling Customers' Energy Management**: In January, Santee Cooper launched SmartRewards, a program that rewards customers who help reduce periods of high demand on the electric system by letting us cycle their HVAC system or hot water heater on and off. SmartRewards joins our EmpowerSC suite of energy management incentives, including rebates for solar panels, energy-efficient appliances and more.

> **Growing Jobs and Investment**: Working alongside other economic development partners, we helped achieve a record year for industrial investment in South Carolina. In 2022, Santee Cooper and the state's electric

cooperatives helped bring more than $4.9 billion in announced investment and nearly 3,500 announced jobs to the state. Highlights include Redwood Materials' $3.5 billion announcement to open a battery recycling facility in Santee Cooper's Camp Hall commerce park; Santee Cooper industrial customer Nucor announcing two expansions at its Berkeley County plant; and DC BLOX announcing a major subsea cable landing station at Myrtle Beach's Industrial Technology and Aerospace Park.

> Keeping the Lights On: In terms of distribution reliability, Santee Cooper again ranked near the top of a national peer group, coming in 7th (top 1.5%) among nearly 500 investor-owned utilities and electric cooperatives.

> Providing Outstanding Customer Satisfaction: We saw increases in customer satisfaction among residential (96.4% satisfied), commercial (97.3% satisfied) and cooperative customers (46.7% satisfied) – and the other two customer groups (industrial and municipal) remained at 100% satisfied.

> Focusing on Safety: Safety remained a top priority at Santee Cooper. For 2022, the Recordable Injury rate was 0.51 incidents per 100 people, and the Preventable Motor Vehicle Accident rate was 0.51 incidents per million miles traveled.

> Protecting the Environment: Santee Cooper's Integrated Resource Plan will focus on a generating path forward that reduces emissions, while meeting the growing needs of this state as more people and businesses move to South Carolina. That plan is on track to be submitted for South Carolina Public Service Commission (PSC) review in May 2023, and the final document will serve as a blueprint for how we do that. Already, several new utility-scale solar projects contracted for in 2021 are under construction and will add important renewable generation to the system, and we intend to seek contracts for additional solar power with PSC approval. We are managing water quality on the Santee Cooper Lakes and developing a unique biological tool to help us safely combat invasive weeds that threaten water quality and navigation. Our energy management programs have goals to help customers reduce energy consumption, which in turn reduces the amount of generation we need to build going forward. And we continue to test opportunities for other innovative solutions that protect our natural resources: As one example last year, Santee Cooper hosted a field test for a fish passage portal designed to help certain fish species – American shad and blueback herring – better navigate our dams and dikes and move upstream to spawn.

Fuel Costs

The primary financial focus throughout 2022 was addressing the impact of high costs and inconsistent availability of the fuel needed to run our generating stations.

A 2021 fire at the mine representing Santee Cooper's largest and lowest-cost coal supplier continued to hurt that mine's output throughout 2022, requiring us to purchase higher-priced replacement coal. Higher natural gas prices, and therefore purchased power costs, continued due to global unrest and impacted electric utilities across the country, including Santee Cooper. Although all of these issues improved as the year came to a close, they did result in net fuel costs exceeding the 2022 budget by about $540 million.

Financial Highlights

Santee Cooper continued to execute a strategic financial plan that included effective debt management and cost controls and allowed continued compliance with a rate freeze that continues through 2024.

Recognizing the likely impact of the fuel issues early, Santee Cooper quickly developed mitigation, including adopting a budget savings goal of $100 million ($30 million in non-fuel operation and maintenance and $70 million in capital). We exceeded that goal and realized savings of about $47 million in non-fuel operation and maintenance costs and $116 million in capital projects for 2022.

Santee Cooper further hedged anticipated natural gas needs, to guard against continued inflation in those markets. We also increased the capacity of our bank credit facilities from $850 million to $1 billion and took other steps to help preserve cash flexibility.

As for debt management, the Board of Directors approved a $1.3 billion tender and exchange bond transaction in February expected to produce approximately $378 million in gross savings – roughly $11 million a year – over the life of the bonds. In November, the Board also approved a $622 million bond sale to refinance approximately $175 million in bonds due in 2023 and provide $450 million for capital investments in our system.

The South Carolina Joint Bond Review Committee authorized both of these bond transactions prior to execution. Santee Cooper also paid down another $85 million in 2023 debt maturities during 2022.

Cook Settlement

Santee Cooper is complying with terms of the Cook Settlement. We paid our final $70 million installment in September, which is being refunded back to customers by a third-party administrator. We also have frozen our rates at levels approved by the Court and documented expenses for events, such as the coal mine fire, which are Court-allowed exceptions to the rate freeze.

Additionally, in June, the Board authorized the use of regulatory accounting for rate freeze exceptions specifically named in our 2020 and 2021 Cook Compliance Reports, including any future adjustments to those exception amounts. This accounting treatment is allowed when certain expenses are incurred in a period other than when they will be collected, and helps Santee Cooper maintain appropriate financial metrics until those expenses can be collected. We will develop a plan to recover expenses related to these exceptions beginning in 2025, after the rate freeze expires.

Storms

Hurricane Ian made landfall near Georgetown, South Carolina, on September 30 as a Category 1 storm. It took 12 Santee Cooper transmission lines out of service and disrupted power to over 70,000 retail customers, affecting both overhead and underground lines because of the large storm surge along the Grand Strand. All customers were restored by the evening of October 2.

The Christmas holiday was ushered in by a Winter Storm Elliott that delivered one of the coldest Christmas storms in recent history to South Carolina and the entire Southeast, straining the power supply and transmission systems throughout the region. Santee Cooper forecasted high demand and prepared for the impact by purchasing additional power, weatherizing our stations and, along with the state's electric cooperatives, executing conservation measures. However, Santee Cooper's ability to meet our soaring customer demand was threatened due to system issues and regional constraints. We executed our emergency plan for such situations and, except for approximately 15 minutes early Christmas Eve, kept power flowing without interruption to our firm customers and to the state's electric cooperatives. Our non-firm customers were curtailed for a longer stretch, within the terms of their contracts, to ensure system stability.

Although all storms have their challenges, Winter Storm Elliott required many folks to work long hours, in difficult conditions, over a cherished holiday period. The Santee Cooper team always rises to the challenge, and because of their dedication and innovation, our customers came through the storm with very little impact.

Conclusion

Santee Cooper is navigating the challenges of the present with a focus on controlling costs without sacrificing service. More importantly, we are investing in the future – a future that holds the same reliable and affordable power and water South Carolina has come to depend on, combined with more innovative programs that help our customers and communities prosper. Our team understands the importance of what we do, each and every day, to help South Carolina thrive. As we like to say, at Santee Cooper, we do something that matters.

Peter McCoy
Chairman

Jimmy Staton
President and CEO

Corporate Statistics

System Data 2022

Miles of transmission system lines[1]: **5,223**

Miles of distribution system lines: **3,119**

Number of transmission substations: **93**

Number of distribution substations: **59**

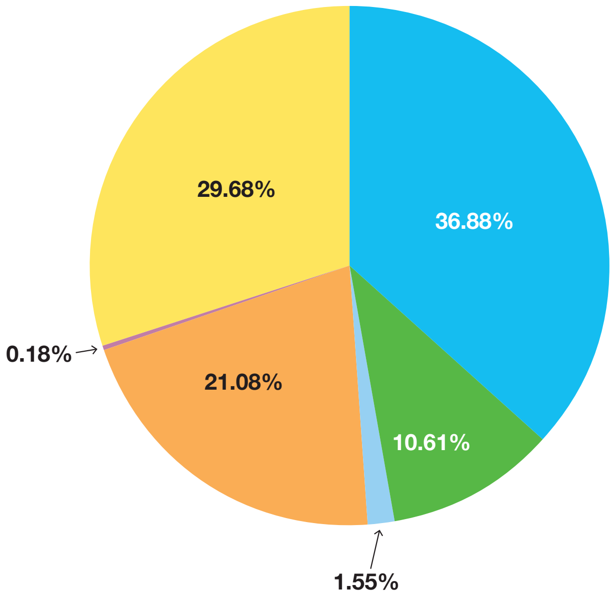
Number of CEPCI Delivery Points (DPs): **421**

[1] Includes Central-owned transmission lines

	2022	2021	2020	2019 As Restated	2018
FINANCIAL (Thousands)					
Total Revenues & Income	**$1,974,737**	$1,854,350	$1,689,760	$1,613,518	$1,963,805
Total Expenses & Interest Charges	**$1,960,898**	$1,801,232	$1,583,275	$1,676,509	$1,766,507
Other	**($1,026)**	$3,146	($54,431)	$48,681	($4,286)
Reinvested Earnings	**$12,813**	$56,264	$52,054	($14,310)[2]	$193,012
OTHER FINANCIAL *(Excluding CP and Other)*					
Debt Service Coverage *(prior to Distribution to State and Special Item)*	**1.27**	1.27	1.46	1.43	1.54
Debt / Equity Ratio	**77/23**	76/24	76/24	76/24	75/25
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**204,766**	198,694	193,930	189,177	185,116
Military and Large Industrial	**27**	27	27	27	27
Wholesale, on system	**4**	4	4	4	4
Wholesale, off system	**4**	4	4	4	4
Total Customers	**204,801**	198,729	193,965	189,212	185,151
Generation (GWh):					
Coal	**9,953**	10,441	8,502	9,126	11,130
Nuclear	**2,863**	2,324	2,570	2,746	2,447
Hydro	**419**	503	756	550	551
Natural Gas and Oil	**5,695**	5,020	5,471	5,582	5,099
Landfill Gas and Renewables	**48**	49	47	56	60
Total Generation (GWh)	**18,978**	18,337	17,346	18,060	19,287
Purchases, Net Interchanges, etc. (GWh)	**8,011**	7,398	6,147	6,451	5,378
Wheeling, Interdepartmental, and Losses	**(765)**	(1,134)	(1,260)	(1,282)	(947)
Total Energy Sales (GWh)	**26,224**	24,601	22,233	23,229	23,718
Summer Generating Capacity (MW)	**5,075**	5,115	5,110	5,110	5,112
Winter Generating Capacity (MW)	**5,293**	5,343	5,338	5,338	5,347
Territorial Peak Demand (MW), Summer	**4,746**	4,505	4,467	4,507	4,458
Territorial Peak Demand (MW), Winter	**5,342**	4,634	4,456	4,558	5,203

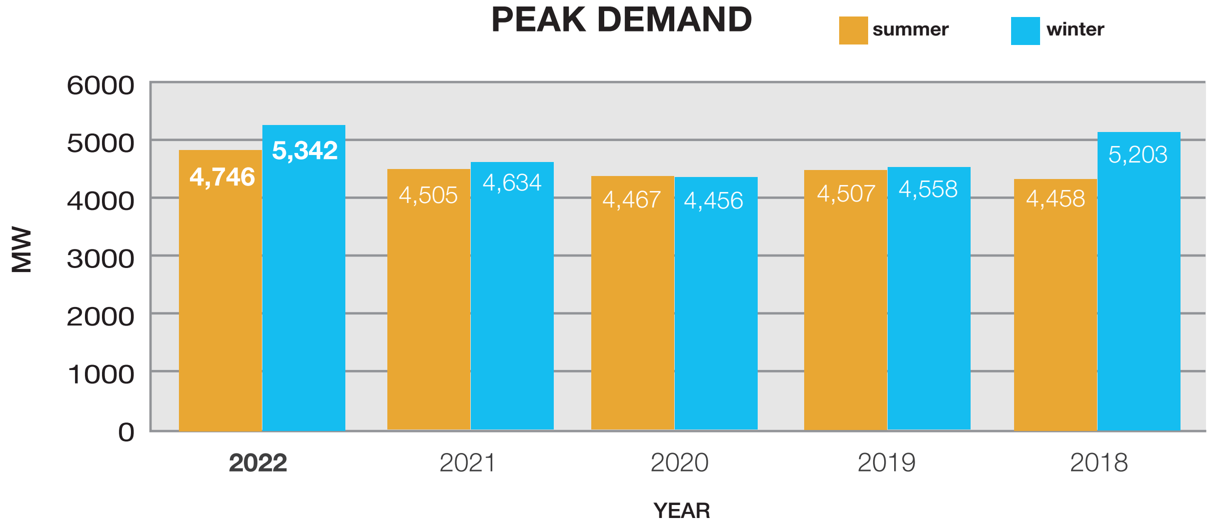
[2] 2019 financial results included a decrease to reinvested earnings from higher net amortization of the Regulatory assets - nuclear over the Deferred inflows - Toshiba settlement. This amortization was to align with impacts from the 2019 debt defeasance as well as capital expenditures.

2022 GENERATION BY FUEL MIX

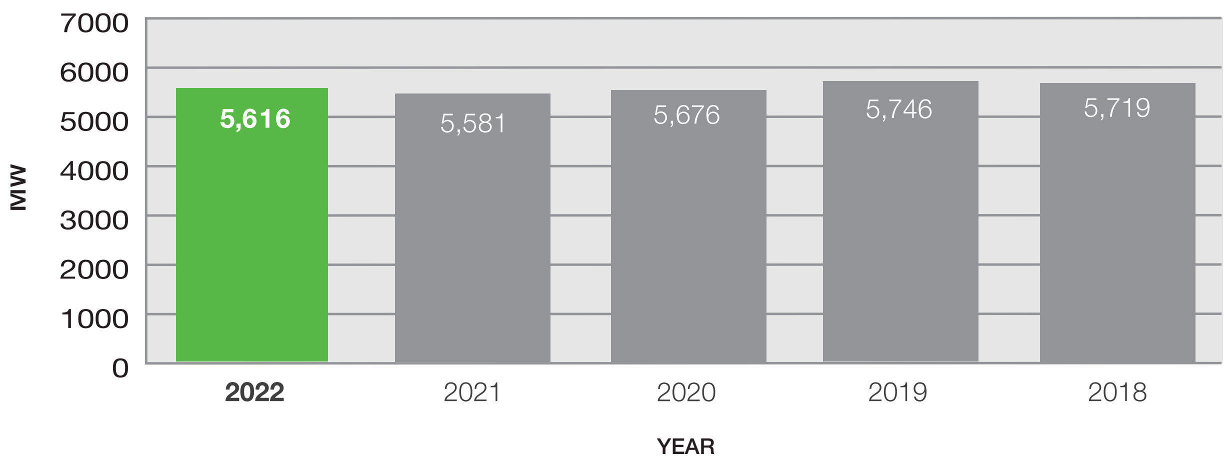


Source		GWh
Coal	36.88%	9,953
Nuclear	10.61%	2,863
Hydro	1.55%	419
Natural Gas	21.08%	5,689
Oil	0.02%	6
total Renewables	0.18%	48
Purchases (Net)	29.68%	8,011
	100.00%	26,989

PEAK DEMAND



TOTAL CAPACITY 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 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
Chairwoman
2022 Audit Committee

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Cherry Bekaert LLP
Your Guide Forward

Report of Independent Auditor

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, 2022 and 2021, 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, 2022 and 2021, 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.

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 15, 2023 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 15, 2023

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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 regulatory related requirements were imposed by Act 90 of 2021 ("Act 90") and are described in the Legislative Matters section on page 24.

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. Summer power supply peak capacity totaled 5,075 megawatts (MW) consisting of 3,460 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 capability Winter power supply peak capacity totaled 5,293 MW consisting of 3,480 MW of coal-fired capacity, 1,315 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 capability.

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 – Other Post Employment Benefits (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, 2022, 2021 and 2020 are summarized below

	2022	2021	2020
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	**$ 4,907,619**	$ 5,003,200	$ 5,065,225
Current assets	**1,669,284**	1,400,548	1,195,349
Other noncurrent assets	**4,788,349**	4,436,986	4,395,151
Deferred outflows of resources	**976,711**	872,566	895,719
Total assets & deferred outflows of resources	**$12,341,963**	$11,713,300	$11,551,444
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	**$ 7,573,550**	$ 6,961,591	$ 6,857,277
Current liabilities	**672,284**	671,887	614,928
Other noncurrent liabilities	**1,239,117**	1,240,899	1,379,405
Deferred inflows of resources	**723,093**	700,143	600,183
Total liabilities & deferred inflows of resources	**$10,208,044**	$ 9,574,520	$ 9,451,793
NET POSITION			
Net invested in capital assets	**$ 1,940,194**	$ 2,010,384	$ 2,090,633
Restricted for debt service	**20,698**	9,214	12,107
Restricted for capital projects	**0**	0	119
Unrestricted (deficit)	**173,027**	119,182	(3,208)
Total net position	**$ 2,133,919**	$ 2,138,780	$ 2,099,651
Total liabilities, deferred inflows of resources & net position	**$12,341,963**	$11,713,300	$11,551,444

2022 COMPARED TO 2021

The primary changes in the Authority's financial condition as of December 31, 2022 and 2021 were as follows:

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

Total assets and deferred outflows of resources increased $628.7 million during 2022 due to increases of $268.7 million in current assets, $351.4 million in other noncurrent assets, and $104.1 million in deferred outflows of resources. These increases were offset by smaller decreases of $95.6 million in capital assets.

The decrease in capital assets of $95.6 million was due to higher accumulated depreciation, offset by capital asset additions. Capital spending was reduced in 2022, resulting in lower capital asset additions. Projects going into service included: new absorber tanks and vessels at Cross Unit 1; Cross Units 3 and 4 reheater work; Cross 1 boiler work and finishing superheater assembly; and the Carnes Crossroads transformer addition.

The increase in current assets of $268.7 million was primarily due to increases in unrestricted and restricted cash and investments of $153.5 million. The net increases came mainly from proceeds received from the 2022 E tax exempt bond proceeds less debt service payments, funding the current year cash defeasances, fund transfers and capital expenditures. Fuel stocks increased $46.1 million due to higher priced fuel and fuel management practices. Accounts receivables increased $44.6 million, primarily caused by increases in the Central Electric Cooperative and The Energy Authority receivables. Also, prepaid expenses & other current assets increased by $38.5 million due mainly to an increase in the current derivative assets. Materials and supplies inventory increased $18.8 million due to higher market prices of commodities. Regulatory assets - nuclear decreased by $28.6 million ~~is~~ due to reduced amortization scheduled for 2023, resulting in less transfers from noncurrent regulatory assets – nuclear.

The increase in other noncurrent assets of $351.4 million resulted from the recording of the Cook Settlement Exceptions regulatory asset of $358.6 million during 2022. This was partially offset by the decreases in noncurrent restricted investments due to an investment loss (including market value adjustments) and a decrease in the noncurrent regulatory asset – nuclear due to transfers to current. Other noncurrent assets netted to small variances between the years.

Deferred outflows of resources increased $104.1 million, due mainly to the increase in Unamortized loss on refunded and defeased debt of $124.4 million resulting from loss additions related to the 2022 AB Refunding bond issue. The accumulated fair value of hedging derivatives also increased by $14.4 million due to higher deferred losses compared to the prior period. The deferred outflow – OPEB increased $16.4 million, resulting from the 2022 actuarial studies driven by the investment experience. These increases were partially offset from a decrease in the deferred outflow – ARO of $34.1 million due to continued ash pond removals.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources increased $633.5 million due to increases of $612.0 million in long-term debt, $0.4 million, in current liabilities, and $22.9 million in deferred inflows of resources. These increases were partially offset by a decrease of $1.8 million in other noncurrent liabilities.

Long-term debt - net increased $612.0 million. This resulted from the net debt increases of $311.7 million related to the 2022 AB Refunding bond issue, 2022 CDEF Refunding and Improvement bond issues, removals of the bonds being refunded along with the March and December cash defeasances. Long Term Revolving Credit Agreements increased by $200.5 million due to current period draws. Unamortized debt discounts and premiums also increased by $99.8 million due mainly to the impact of the associated 2022 net bond activity.

The increase in current liabilities of $400,000 was due mainly to increases in other current liabilities of $45.0 million and an increase of $27.3 million in accounts payable. These increases were partially offset by a decrease of $68.3 million in the current portion of long-term debt. The other current liabilities increase was primarily a result of a higher deferred liability offset of $75.8 million in hedging collateral received, partially offset by a $70.0 million decrease in the Cook Settlement Agreement liability. The accounts payable increase resulted from higher purchased power liabilities partially offset by lower Summer nuclear accounts payables. Current portion - long term debt decreased due mainly to lower principal payments under debt service requirements.

The decrease in other noncurrent liabilities of $1.8 million resulted mainly from a reduction of $38.9 million in the asset retirement obligation because of continued ash pond removals in 2022. This was offset by increases in the net pension of $14.1 million and net OPEB liabilities of $14.5 million, resulting from the 2022 actuarial study updates with lower investment assumptions for the current year. Further offsetting the decrease was an increase of $8.5 million in the deferred liability account for Camp Hall sales.

Deferred inflows of resources increased $22.9 million largely due to higher accumulated increase in fair value of hedging derivatives of $89.2 million, resulting from higher mark to market gains associated with higher natural gas prices increasing future settle prices. This was partially offset by decreases in deferred inflows – nuclear decommissioning costs of $41.4 million, mainly from lower market values and reduced funding due to changes in projected earnings rates and NRC required minimum funding; deferred inflows - pension of $13.7 million associated with changes in assumptions and better investment performance in the 2022 actuarial study; and deferred inflows - Toshiba settlement amortization of $9.1 million. Further offsets were provided by deferred inflow - OPEB of $2.1 million from changes in the 2022 actuarial study.

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 Agreement (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 2021 AB 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.

RESULTS OF OPERATIONS

Santee Cooper's Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2022, 2021 and 2020 are summarized as follows:

	2022	2021	2020
		(Thousands)	
Operating revenues	**$ 1,949,050**	$ 1,765,785	$ 1,627,427
Operating expenses	**1,670,010**	1,496,286	1,263,683
Operating income	**279,040**	269,499	363,744
Interest expense	**(299,286)**	(304,946)	(319,592)
Costs to be recovered from future revenue	**(1,026)**	3,145	(54,431)
Other income	**34,086**	88,566	62,333
Transfers	**(17,675)**	(17,135)	(17,479)
Change in net position	**$ (4,861)**	$ 39,129	$ 34,575
Net position - beginning of period	**$ 2,138,780**	$ 2,099,651	$ 2,065,076
Ending net position	**$ 2,133,919**	$ 2,138,780	$ 2,099,651

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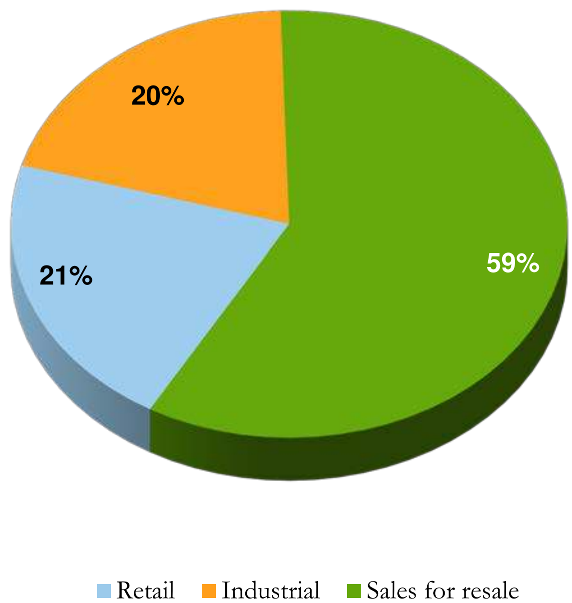
2022 Compared to 2021

Operating Revenues

Compared to 2021, operating revenues increased $183.3 million (10%), primarily from higher fuel rate revenues of $77.0 million, mainly in the Industrial category. Higher energy sales (7%), demand usage (8%) and demand rate revenues also increased revenues by $40.7 million, $31.1 million and $18.7 million, respectively. Degree day increases of 5% contributed to increased revenues in our retail and wholesale businesses. Further contributions were made by higher off system Municipal sales of $14.7 million. Also contributing was the change between the periods for the Central Cost of Service adjustments of $15.2 million. The 2021 adjustments were higher due to the finalization of 2020's adjust-to-actual and accruals for 2016, 2017 and 2018's audit issues of $21.6 million. In addition, the 2021 adjust-to-actual accrual was $2.4 million higher as compared to 2022. The 2022 adjustments included accruals for 2018 & 2019 audit issues of $8.0 million. Somewhat offsetting these increases were lower O&M rate revenues of $12.3 million. Energy sales for 2022 totaled approximately 26.2 million megawatt hours (MWhs), as compared to approximately 24.6 million MWhs for 2021.

2022 Revenues from Sales of Electricity*
by Customer Class

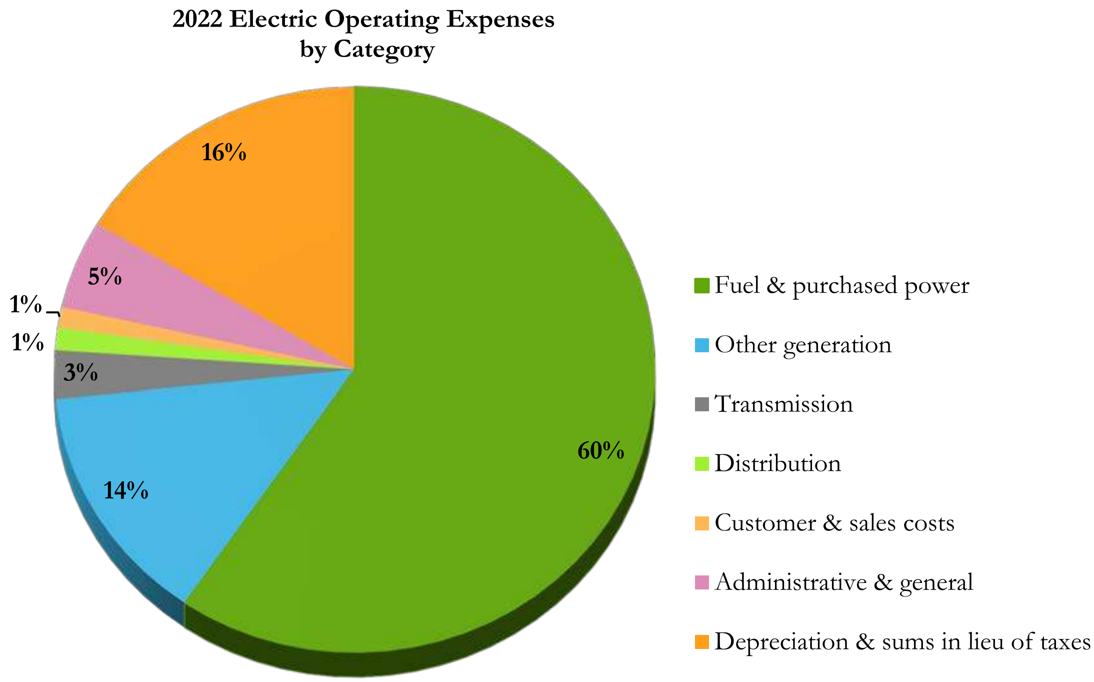


		2022		2021		2020
Revenues from Sales of Electricity*				(Thousands)		
Retail	**$**	**405,973**	$	406,969	$	383,267
Industrial		**386,211**		274,202		196,683
Sales for resale		**1,131,579**		1,059,588		1,022,398
Totals	**$**	**1,923,763**	$	1,740,759	$	1,602,348

* Excludes interdepartmental sales of $615 for 2022, $582 for 2021 and $577 for 2020.

OPERATING EXPENSES

Operating expenses for 2022 increased $173.7 million (12%) as compared to 2021 fuel and purchased power credits of $327.1 million from the Cook Settlement Exceptions regulatory asset. Primary drivers were higher: (i) fuel and purchased power expense of $548.0 million from higher kWh sales, higher commodity prices for the generation mix utilized and increased use of higher cost purchased power due to coal stockpile management, as well as higher costs in the energy markets due to elevated natural gas prices; (ii) depreciation of $10.6 million from assets placed into service in the current year; (iii) distribution of $3.5 million from higher labor and contract services in the current year; and (iv) transmission of $3.3 million from higher transmission purchases associated with purchased power. Further offsetting these increases were lower: (i) non-fuel generation of $59.6 million mainly from lower contract services and materials due largely to smaller Cross, Winyah and Rainey maintenance outage scopes. V.C. Summer expenses were lower due to higher software integration expense in the prior year; and (ii) administrative & general of $6.7 million from contract services due to lower legal expense. Non-fuel generation and administrative & general are shown net of credits from the Cook Settlement Exceptions regulatory asset of $16.7 million and $5.4 million, respectively.



		2022		2021		2020
Electric Operating Expenses				(Thousands)		
Fuel & purchased power	**$**	**991,017**	$	770,115	$	597,636
Other generation		**229,251**		288,840		227,679
Transmission		**45,679**		42,338		38,904
Distribution		**21,515**		17,997		17,413
Customer & sales costs		**19,528**		17,903		22,051
Administrative & general		**84,099**		90,844		105,608
Depreciation & sums in lieu of taxes		**272,747**		262,134		248,245
Totals	**$**	**1,663,836**	$	1,490,171	$	1,257,536

Net Below the Line Items

- Regulatory amortization and other income provided a combined increase to non-operating expense of $63.0 million, in 2022 as compared to 2021, resulting primarily from lower amortization of the Toshiba regulatory liability of $36.2 million, higher amortization of the nuclear regulatory asset of $49.0 million associated with the cash defeasance of nuclear bonds in December of 2022 and lower TEA income of $11.7 million in the current year. This was offset by higher Summer Nuclear 2 & 3 sales of $23.3 million, interest income of $4.5 million, an increase in the fair value of investments of $2.8 million and the Hearn settlement expense in the prior year of $2.8 million.

- Interest charges decreased $14.0 million, resulting mainly from the 2021 A Refunding in late 2021 and the 2022 AB Refunding in February 2022, as well as the Cook Settlement Exceptions regulatory asset which lowered interest charges by $8.4 million.

- CTBR expense was higher year over year by $4.2 million as a result of higher principal amortization in the current year. The change of water CTBR was $361,000 between the years as a result of debt paydowns.

- Transfers represent dollars paid to the State.

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 an industrial customer and increased production requirements with another industrial customer, 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 due to the new agreement with the industrial customer'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.

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.

Net Below the Line Items

- Regulatory amortization and other income provided a combined increase of $29.0 million in 2022 as compared to 2021. This resulted 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 expense and amortization income 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.

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 our electric cooperative and municipal partners. 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 $111.0 million throughout South Carolina in product development activities through low interest revolving loans to public entities.

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 2022, including Redwood Materials at Camp Hall in Berkeley County, Europastry in Laurens County, and Kontrolmatik Technologies in Colleton County, among others.

The Authority's largest customer, Central Electrical Power Cooperative, Inc (Central), accounted for 55 percent of sales revenues in 2022. 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 that extend through December 31, 2058.

In May 2013, the Authority and Central approved an amendment to their contract (the "Coordination Agreement") and agreed to extend their termination rights. 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's power supply agreements with their new member cooperatives obligates those members to pay their share of Central's costs, including costs paid under the Coordination Agreement. The Authority and Central have also resolved certain matters relating to the nuclear project through the execution of the Cook Settlement Agreement and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement.

2022 was impacted by the continuation of high natural gas and power market prices which began with circumstances dating back to 2019. 2019-2020's low gas prices, an uncertain regulatory environment, labor shortages, and an overall reduction in demand during the COVID-19 Pandemic changed the business plans for many coal suppliers who subsequently took their production capacity offline or reduced their production. With the reduction in supply and demand, coal transportation providers also furloughed employees and stored assets. Beginning in 2021, demand rebounded faster and stronger than expected and gas prices rose to levels that would typically trigger gas to coal fuel switching. However, coal supply was still limited because it takes time for coal producers to ramp back up. Additionally, the Authority's largest and lowest cost coal supplier was unable to produce coal due to a fire at their mining complex. After many months of repairs and regulatory hurdles, in February 2022 the mine returned to just 50% production, where it continues to operate. Because that coal supply was curtailed, the Authority re-entered the coal market to procure replacement coal at the then current market price which was considerably higher due to market dynamics which began to include global competition as the Russia-Ukraine conflict was escalating. Coal transportation was also, in part, affected by the COVID-19 pandemic because it created labor shortages which slowed deliveries of coal. Because of those transportation constraints, beginning in the first quarter of 2021, the Authority implemented measures to conserve coal inventory. The Authority continued implementation of these coal conservation efforts throughout 2021 and through the first three quarters of 2022 due to coal inventory levels being below operational target levels; coal inventory did not return to the target range until late October 2022.

Because use of coal was hindered, the Authority was forced into the natural gas and power markets where prices were elevated beginning mid-2021 throughout 2022. The annual average natural gas commodity price in 2022 was over 50% higher than in 2021 and 225% higher than 2020, which was higher due to market dynamics which began to include global competition as the Russia-Ukraine conflict created volatility in global energy markets. Although the Authority had hedged most of its projected natural gas commodity needs and a small amount of projected market purchases to help manage its fuel position during the rate freeze period, the additional volumes switching from coal to natural gas and purchased energy was priced much higher than projected. The annual average natural gas commodity price in 2022 was over 50% higher than in 2021 and 225% higher than 2020. In mid-2022, natural gas transportation prices were impacted negatively by an opportunistic maintenance outage on the Transco pipeline following the Freeport LNG explosion's curtailment of LNG export volume; market participants were forced to re-direct flows which caused unprecedented upheaval of basis prices. In December 2022, Winter Storm Elliott pushed all market prices up further and the Authority was forced to participate in those markets to cover demand requirements on it's system.

The Authority's targeted range for coal on hand is 800 thousand to 1.2 million tons. As of December 31, 2022, the Authority had approximately 1.023 million tons of coal on hand, which equates to approximately 71 days of inventory based on average daily burns projected for 2023.

The Authority has continued to experience reduction in its contracted coal deliveries resulting from production and transportation issues initially caused by the COVID-19 pandemic and subsequently by a fire at and resulting closure of a coal mine operated by the Authority's largest and lowest cost coal supplier (the "Coal Supplier"). The Coal Supplier had been expected to provide approximately 70% of the Authority's coal supply for 2022. The coal mine was closed in August 2021 by the U.S. Mine Safety and Health Administration ("MSHA") after the fire. Partial coal production from the Coal Supplier resumed in February of 2022, and the supply to the Authority continues at a level equal to 50% of the Authority's contracted coal amounts. The Coal Supplier has provided an estimated range of possible dates for restoration to full production levels at the coal mine, but a full reopening of the mine is subject to the approval of the MSHA and cannot be predicted at this time.

Since the Authority cannot predict when the full amount of contracted coal deliveries from the Coal Supplier will resume, the Authority has assumed coal deliveries from the Coal Supplier will remain at 50% of the contracted amounts through at least 2023. Under the terms of the Authority's existing agreement with the Coal Supplier, contracted volumes in 2024 are scheduled to reduce by roughly 50% of the annual contracted volumes for 2021-2023.

The Authority has executed multiple coal supply contracts ranging from one month to approximately two and one-half years to secure replacement coal from alternate sources to supplement a portion of the Coal Supplier's shortfall that is not being replaced with natural gas and purchased power.

In addition, the Authority is currently charging most customers based on the Settlement Rates defined in the Cook Settlement Agreement (See Note 5 - *Cook Settlement as to Rates*), which does not include an adjustment mechanism based on the Authority's actual cost of fuel. The extent of these cost increases is yet to be determined; however, the Authority continues to monitor market conditions and evaluate options to mitigate the impact on stockpiles, costs, and revenues beyond 2022.

Legislative Matters

On June 8, 2021, the General Assembly passed, and on June 15, 2021, the Governor signed into law Act 90, which established reforms by amending the state laws applicable to the Authority.

Changes under Act 90 include new board qualifications and duties, a new rate process for the Authority. Joint Bond Review Committee approval of proposed debt issuance, certain oversight authority to the Office of Regulatory Staff, and new requirements for the SC Public Service Commission (SCPSC) to approve the Authority's Integrated Resource Plan and new generation facilities. The Authority is complying with Act 90 and the Act's changes are being incorporated into the regular operations of the Authority.

Since the enactment of Act 90, the Joint Bond Review Committee has approved several Authority real estate and financing transactions, the SCPSC has opened dockets related to the Authority's renewable energy procurement and future resource plans, the Governor has appointed a new Authority Chair who has been confirmed by the SC Senate, and the Agency Head Salary Commission has approved the compensation package for the Authority's current CEO.

During the 2022 state legislative session, the South Carolina General Assembly adopted a budget that included a proviso authorizing the Office of Regulatory Staff to charge the Authority for its annual regulatory expenses associated with Act 90. The budget proviso provided for these annual amounts to be deducted from the Authority's annual payment to the State, thereby avoiding an additional expense to the Authority's customers. Through the year ended December 31, 2022, no amounts have been deducted from the Authority's payment to the State.

The 2023-2024 SC legislative session began January 10, 2023, and two items on the South Carolina General Assembly's agenda include: 1) an anticipated report from the Electricity Market Reform Measures study committee, a joint legislative committee consisting of 4 Senators and 4 House members, analyzing market options for South Carolina; and, 2) economic development related legislation to include energy provisions, being considered and developed by a special SC House Ad Hoc committee appointed by the Speaker of the SC House of Representatives.

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 2022, 2021 and 2020 was as follows:

Approved in:		**2022**		2021		2020
		Budget 2023-25		Budget 2022-24		Budget 2021-23
Capital Improvement Expenditures				(Thousands)		
Environmental compliance [1]	**$**	**286,757**	$	241,824	$	167,622
Load and Resource Plan [2]		**219,727**		0		0
Property Acquisition [2]		**5,135**		0		0
General improvements and Other [3]		**813,581**		723,266		701,263
Totals	**$**	**1,325,200**	$	965,090	$	868,885

1 Project costs are associated with ash pond closures, solid waste landfill construction, and installation of wastewater treatment systems.
2 Reflects future generation costs associated with the load and resource plan. "Property Acquisition" accounts for a purchase of land that can be resold if not used.
3 Budget 2023-25 reflects ongoing improvements to existing generating resources and FERC Relicensing. "Other" includes Camp Hall and transmission improvements due to load growth.

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 (SCANA's subsidiary; SCANA was acquired by Dominion Energy on January 1, 2019 and established Dominion Energy South Carolina (DESC) as a wholly owned subsidiary of SCANA) (55% ownership interest) (together, the "Owners").

On July 31, 2017, the Authority approved the wind-down and suspension of construction of the Summer Nuclear Units 2 and 3 at the Virgil C. Summer Nuclear Generating Station and the preservation and protection of the site and related components and equipment.
The Authority had spent approximately $4.7 billion in construction and interest costs. Upon suspending construction, and in accordance with GASB No. 62, the Authority ceased capitalizing interest expense on the debt incurred to fund Summer Nuclear Units 2 and 3 as of July 31, 2017. With the exception of certain assets to be repurposed at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the fuel assets and non-fuel assets comprising Summer Nuclear Units 2 and 3 were determined in accordance with GASB No. 42 to be impaired.

Impairment and 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 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 in accordance with GASB 42 to be impaired.

Regulatory Accounting for Summer Nuclear Units 2 and 3. 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 (i) a portion of post-suspension capitalized interest in the amount of $37.1 million to be amortized through November 2056 in order to align with the principal payments on the debt used to pay the interest and (ii) the recognition of income from the settlement agreement with the Toshiba Corporation ("Toshiba") relating to Toshiba's guaranty of certain payment obligations in respect of Summer Nuclear Units 2 and 3 (the "Toshiba Settlement Agreement") in the amount of $898.2 million, to be amortized over time to align with the manner in which the settlement proceeds are used to reduce debt service payments.

The following table summarizes the nuclear-related regulatory items:

Regulatory Item	Classification	Original Amount	2018 - 2022 Amortization	2018 - 2022 Changes	2022 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($ 529.3 million)	($40.2 million)	$ 3.642 billion
Nuclear post-suspension interest	Asset	$ 37.1 million	$ (33,000)		$ 37.1 million
Toshiba Settlement Agreement	Deferred Inflow	$ 898.2 million	($ 670.0 million)	$13.8 million	$ 242.0 million

Sales of Summer Nuclear Units 2 and 3 Assets. During calendar years 2018 - 2022, the Authority sold certain equipment and commodities to third parties. The Authority expects to use the net proceeds received from the sale of the nuclear-related equipment to pay down a portion of its outstanding debt. Through December 31, 2022, $78.6 million of materials have been sold.

Financing Activities

On February 8, 2022, Santee Cooper priced approximately $931.0 million of the 2022 Tax-Exempt Refunding Series A bonds to purchase from investors their outstanding high-coupon bonds and $352.0 million of the 2022 Tax-Exempt Refunding Series B bonds to exchange high-coupon bonds with investors. The 2022 AB Refunding bonds mature in years 2023-2055. The refunding produced approximately $378.0 million in gross savings which results in approximately $250.0 million in net present value debt service savings. The 2022 AB Refunding bonds closed on February 23, 2022.

On November 8, 2022, Santee Cooper priced approximately $37.0 million of 2022 Tax-Exempt Refunding Series C and $135.0 million of 2022 Taxable Refunding Series D to refinance approximately $175.0 million of the 2016 Series D bonds that are due in 2023. Santee Cooper also priced approximately $390.0 million (2022 CD Refunding bonds) 2022 Tax-Exempt Improvement Series E and $60.0 million 2022 Taxable Improvement Series F (2022 EF Improvement bond) to fund environmental compliance, transmission projects and capital improvement projects related to existing generation units. The 2022 CD Refunding bonds mature in years 2023-2042. The 2022 EF Improvement bonds mature in years 2023-2052. The 2022 CDEF bonds closed on November 15, 2022.

Liquidity and Capital Resources

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

On December 31, 2022, Santee Cooper had $1.1 billion of cash and investments, of which $462.9 million was available for liquidity purposes to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $203.4 million.

The Authority has entered into Reimbursement Agreements and secured irrevocable direct-pay letters of credit with Barclays Bank PLC to support the issuance of commercial paper notes totaling $300.0 million as of December 31, 2022. As of December 31, 2022, the Authority had $118.2 million of commercial paper notes outstanding.

To obtain other funds, if needed, the Authority entered into Revolving Credit Agreements with Bank of America, N.A, J.P. Morgan Chase Bank, N.A, TD Bank, N.A, and Wells Fargo, N.A. These agreements allow the Authority to borrow up to $700.0 million and expire at various dates. On December 31, 2022, the Authority has secured $219.5 million under the Direct Purchase Revolving Credit Agreements.

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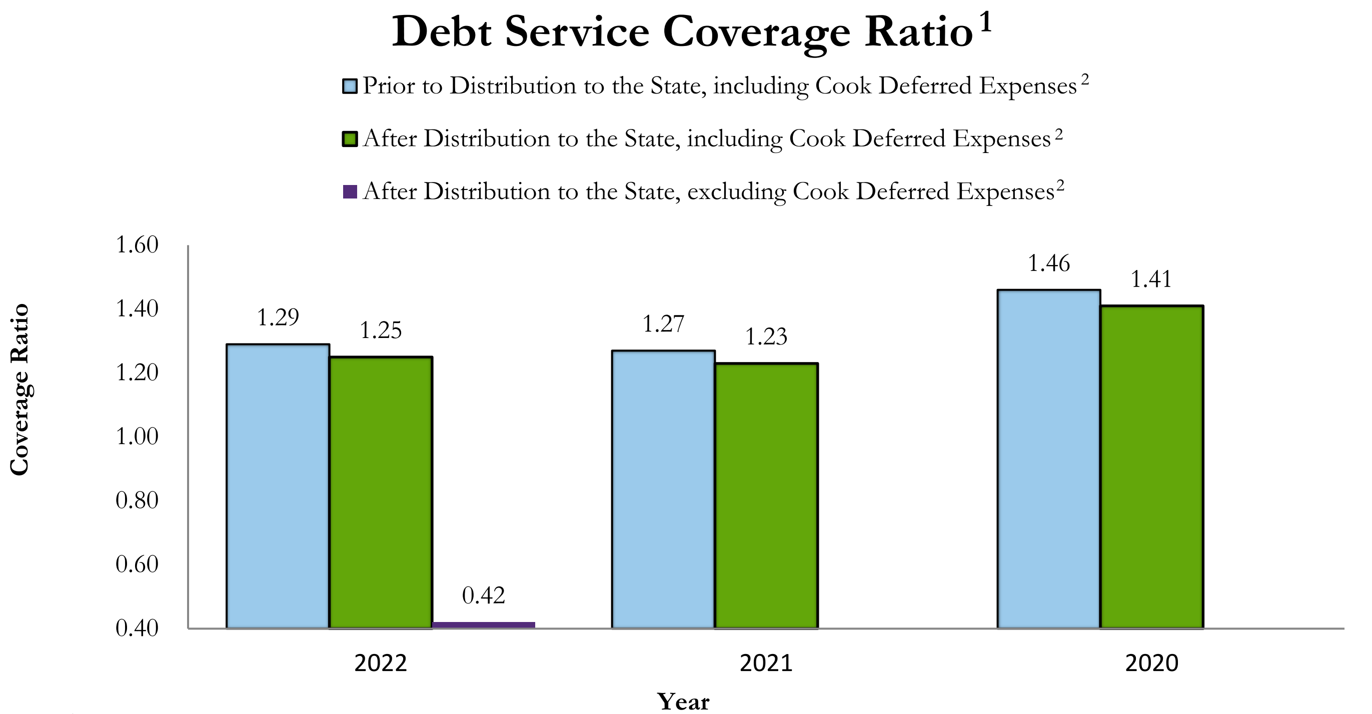
DEBT SERVICE COVERAGE

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2022, 2021 and 2020 is shown below:



[1] Excluding commercial paper and other.

[2] See Note 5 - *Cook Settlement as to Rates.*

BOND RATINGS

Bond ratings assigned by various agencies as of December 31, 2022, 2021 and 2020 were as follows:

Agency / Lien Level	2022	2021	2020
Fitch Ratings			
Revenue Obligations	**A-**	A-	A-
Commercial Paper[1]	**F1**	F1	F1
Outlook	**Negative**	Stable	Stable
Moody's Investors Service, Inc.			
Revenue Obligations	**A3**	A2	A2
Commercial Paper[1]	**P-1**	P-1	P-1
Outlook	**Negative**	Stable	Stable
Standard & Poor's Rating Services			
Revenue Obligations	**A-**	A	A
Commercial Paper[1]	**A-1**	A-1	A-1
Outlook	**Negative**	Stable	Negative

[1] In 2020, the Authority entered into Direct Pay Letters of Credit issued by Barclay's Bank, PLC supporting the commercial paper program.

Bond Market Transactions for Years 2022, 2021 and 2020

YEAR 2022

Revenue Obligations:	**2022 Tax-Exempt Refunding Series A**	**Par Amount:**	$ 930,990,000
Purpose:	Refund a portion of the following: 2013 Series A, 2013 Refunding Series B, 2013 Series E, 2014 Series A, 2014 Refunding Series B, 2014 Refunding Series C, 2015 Series A, 2015 Series E	**Date Closed:**	February 23, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 3.31 percent		
Revenue Obligations:	**2022 Tax-Exempt Refunding Series B**	**Par Amount:**	$ 352,201,000
Purpose:	Refund a portion of the following: 2013 Series A, 2013 Refunding Series B, 2013 Series E, 2014 Series A, 2014 Refunding Series B, 2014 Refunding Series C, 2015 Series A, 2015 Series E	**Date Closed:**	February 23, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 3.31 percent		
Revenue Obligations:	**2022 Tax-Exempt Refunding Series C**	**Par Amount:**	$ 36,640,000
Purpose:	Refund all of the 2016 Series D	**Date Closed:**	November 15, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 4.85 percent		
Revenue Obligations:	**2022 Taxable Refunding Series D**	**Par Amount:**	$ 134,850,000
Purpose:	Refund all of the 2016 Series D	**Date Closed:**	November 15, 2022
Comments:	Taxable bond with an all-in true interest cost of 6.56 percent		
Revenue Obligations:	**2022 Tax-exempt Improvement Series E**	**Par Amount:**	$ 390,000,000
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	November 15, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 5.26 percent		
Revenue Obligations:	**2022 Taxable Improvement Series F**	**Par Amount:**	$ 60,000,000
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	November 15, 2022
Comments:	Taxable bond with an all-in true interest cost of 6.47 percent		

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		

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, 2022 and 2021

	2022	2021
	(Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents	**$ 299,284**	$ 299,487
Unrestricted investments	**163,567**	303,625
Restricted cash and cash equivalents	**53,175**	36,630
Restricted investments	**459,517**	182,343
Receivables, net of allowance for doubtful accounts of $2,469 and $2,560 at December 31, 2022 and 2021, respectively	**220,458**	175,810
Materials inventory	**171,731**	152,950
Fuel inventory		
Fossil fuels	**100,125**	54,011
Nuclear fuel - net	**100,544**	105,747
Interest receivable	**2,357**	1,344
Regulatory assets - nuclear	**7,911**	36,482
Prepaid expenses and other current assets	**90,615**	52,119
Total current assets	**1,669,284**	1,400,548
Noncurrent assets		
Restricted cash and cash equivalents	**373**	269
Restricted investments	**123,778**	152,254
Capital assets		
Utility plant	**9,020,408**	8,800,734
Long lived assets - asset retirement cost	**266,981**	266,981
Accumulated depreciation	**(4,619,865)**	(4,422,072)
Total utility plant - net	**4,667,524**	4,645,643
Construction work in progress	**214,373**	331,065
Other physical property - net	**25,722**	26,492
Investment in associated companies	**26,057**	21,956
Costs to be recovered from future revenue	**221,960**	222,986
Regulatory assets - OPEB	**152,497**	152,497
Regulatory assets - nuclear	**3,670,734**	3,697,704
Regulatory assets - Cook Settlement Exceptions	**358,605**	0
Other noncurrent and regulatory assets	**234,345**	189,320
Total noncurrent assets	**9,695,968**	9,440,186
Total assets	**$ 11,365,252**	$ 10,840,734
DEFERRED OUTFLOWS OF RESOURCES		
Deferred outflows – pension	**$69,402**	$53,010
Deferred outflows - OPEB	**57,539**	49,090
Regulatory asset-asset retirement obligation	**638,709**	672,804
Accumulated decrease in fair value of hedging derivatives	**25,621**	11,264
Unamortized loss on refunded and defeased debt	**185,440**	86,398
Total deferred outflows of resources	**$ 976,711**	$ 872,566
Total assets & deferred outflows of resources	**$ 12,341,963**	$ 11,713,300

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, 2022 and 2021

		2022		2021
		(Thousands)		
LIABILITIES				
Current liabilities				
Current portion of long-term debt	**$**	**39,525**	$	107,791
Accrued interest on long-term debt		**40,456**		38,324
Revolving credit agreement		**0**		3,211
Commercial paper		**118,246**		120,832
Accounts payable		**215,268**		187,979
Other current liabilities		**258,789**		213,750
Total current liabilities		**672,284**		671,887
Noncurrent liabilities				
Construction liabilities		**3,781**		2,286
Net OPEB liability		**203,817**		189,328
Net pension liability		**308,586**		294,504
Asset retirement obligation liability		**630,526**		669,419
Total long-term debt (net of current portion)		**7,066,226**		6,554,026
Unamortized debt discounts and premiums		**507,324**		407,565
Long-term debt-net		**7,573,550**		6,961,591
Other credits and noncurrent liabilities		**92,407**		85,362
Total noncurrent liabilities		**8,812,667**		8,202,490
Total liabilities	**$**	**9,484,951**	$	8,874,377
DEFERRED INFLOWS OF RESOURCES				
Deferred inflows - pension	**$**	**61,848**	$	75,525
Deferred inflows - OPEB		**7,334**		9,388
Accumulated increase in fair value of hedging derivatives		**207,449**		118,208
Nuclear decommissioning costs		**204,486**		245,933
Regulatory inflows – Toshiba settlement		**241,976**		251,089
Total deferred inflows of resources	**$**	**723,093**	$	700,143
NET POSITION				
Net investment in capital assets	**$**	**1,940,194**	$	2,010,384
Restricted for debt service		**20,698**		9,214
Unrestricted		**173,027**		119,182
Total net position	**$**	**2,133,919**	$	2,138,780
Total liabilities, deferred inflows of resources & net position	**$**	**12,341,963**	$	11,713,300

Statements of Revenues, Expenses and Changes in Net Position - Business – Type Activities

South Carolina Public Service Authority

Years Ended December 31, 2022 and 2021

	2022	2021
	(Thousands)	
Operating revenues		
Sale of electricity	**$ 1,923,763**	$ 1,740,759
Sale of water	**7,574**	8,705
Other operating revenue	**17,713**	16,321
Total operating revenues	**1,949,050**	1,765,785
Operating expenses		
Electric operating expenses		
Production	**139,015**	156,700
Fuel	**559,432**	466,191
Purchased and interchanged power	**431,585**	303,924
Transmission	**36,828**	32,279
Distribution	**15,546**	11,606
Customer accounts	**16,237**	16,248
Sales	**3,291**	1,655
Administrative and general	**70,182**	81,126
Electric maintenance expenses	**118,973**	158,308
Water operating expenses	**4,154**	3,726
Water maintenance expenses	**766**	918
Total operating and maintenance expenses	**1,396,009**	1,232,681
Depreciation	**269,073**	259,075
Sums in lieu of taxes	**4,928**	4,530
Total operating expenses	**1,670,010**	1,496,286
Operating income	**279,040**	269,499
Nonoperating revenues (expenses)		
Interest and investment revenue	**6,751**	2,075
Net increase (decrease) in the fair value of investments	**1,230**	(1,558)
Interest expense on long-term debt	**(302,680)**	(313,175)
Interest expense on commercial paper and other	**(7,992)**	(6,306)
Amortization income	**19,784**	14,535
(Costs) credit to be recovered from future revenue	**(1,026)**	3,146
U.S. Treasury subsidy on Build America Bonds	**7,669**	7,703
Regulatory Amortization - net	**(46,427)**	45,331
Other - net	**56,465**	35,014
Total nonoperating revenues (expenses)	**(266,226)**	(213,235)
Income before transfers	**12,814**	56,264
Transfers		
Distribution to the State	**(17,675)**	(17,135)
Change in net position	**(4,861)**	39,129
Net position – beginning of period	**2,138,780**	2,099,651
Total net position – ending	**$ 2,133,919**	$ 2,138,780

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, 2022 and 2021

	2022	2021
Cash flows from operating activities		(Thousands)
Receipts from customers	**$ 1,907,220**	$ 1,799,960
Payments to non-fuel suppliers	**(384,315)**	(395,367)
Payments for fuel	**(629,329)**	(455,810)
Purchased power	**(688,753)**	(303,921)
Payments to employees	**(222,616)**	(171,483)
Other receipts-net	**206,190**	175,514
Net cash provided by operating activities	**188,397**	648,893
Cash flows from non-capital related financing activities		
Distribution to the State	**(17,675)**	(17,135)
Proceeds from revolving credit agreement draw	**210,360**	0
Repayment of revolving credit agreement draw	**(10,000)**	0
Proceeds from issuance of commercial paper notes	**6,200**	500
Repayment of commercial paper notes	**(13,533)**	(16,392)
Refunding/defeasance of long-term debt	**(965,763)**	0
Proceeds from sale of bonds	**974,682**	0
Repayment of long-term debt	**(30,545)**	(6,644)
Interest paid on long-term debt	**(170,672)**	(186,670)
Interest paid on commercial paper and other	**(2,478)**	(1,294)
Other-net	**(5,432)**	20,296
Net cash used in non-capital related financing activities	**(24,856)**	(207,339)
Cash flows from capital-related financing activities		
Proceeds from revolving credit agreement draw	**9,100**	0
Repayment of revolving credit agreement draw	**(12,211)**	(22,889)
Proceeds from issuance of commercial paper notes	**13,814**	65,160
Repayment of commercial paper notes	**(9,067)**	(99,687)
Refunding/defeasance of long-term debt	**(587,653)**	(282,925)
Proceeds from sale of bonds	**971,423**	521,674
Repayment of long-term debt	**(77,246)**	(98,051)
Interest paid on long-term debt	**(120,886)**	(123,949)
Interest paid on commercial paper and other	**(3,880)**	(4,858)
Construction and betterments of utility plant	**(218,901)**	(204,506)
Other-net	**(9,915)**	7,378
Net cash used in capital related financing activities	**(45,422)**	(242,653)
Cash flows from investing activities		
Proceeds from the sale and maturity of investment securities	**1,231,963**	973,410
Purchase of investment securities	**(1,340,603)**	(1,154,572)
Unrealized gains (losses) on investments	**1,230**	1,558
Interest on investments	**5,737**	5,004
Net cash used in investing activities	**(101,673)**	(174,600)
Net increase in cash and cash equivalents	**16,446**	24,301
Cash and cash equivalents-beginning	**336,386**	312,085
Cash and cash equivalents-ending	**$ 352,832**	$ 336,386

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, 2022 and 2021

		2022		2021
		(Thousands)		
Reconciliation of operating income to net cash provided by operating activities				
Operating income	**$**	**279,040**	$	269,499
Adjustments to reconcile operating income to net cash provided by operating activities				
Depreciation		**269,073**		259,075
Amortization of nuclear fuel		**18,619**		16,445
Net power gains (losses) involving associated companies		**(250,532)**		(81,001)
Distributions from associated companies		**249,049**		82,860
Advances to/from associated companies		**2,514**		14,253
Changes in assets and liabilities				
Accounts receivable-net		**(44,648)**		34,353
Inventories		**(64,895)**		19,222
Prepaid expenses		**(52,355)**		(24,693)
Other deferred debits		**(368,697)**		(46,821)
Accounts payable		**24,685**		54,617
Other current liabilities		**79,733**		102,944
Other noncurrent liabilities		**46,811**		(51,860)
Net cash provided by operating activities	**$**	**188,397**	$	648,893
Composition of cash and cash equivalents				
Current				
Unrestricted cash and cash equivalents	**$**	**299,284**	$	299,487
Restricted cash and cash equivalents		**53,175**		36,630
Noncurrent				
Restricted cash and cash equivalents		**373**		269
Cash and cash equivalents at the end of the year	**$**	**352,832**	$	336,386
Noncash capital activities-Accounts Payable	**$**	**8,866**	$	6,262

Statements of Fiduciary Net Position - OPEB Trust Fund
South Carolina Public Service Authority
As of December 31, 2022, and 2021

		2022		2021
		(Thousands)		
ASSETS				
Cash and cash equivalents	**$**	**4,239**	$	1,367
Investments		**85,192**		108,376
Total current assets		**89,431**		109,743
Total assets	**$**	**89,431**	$	109,743
LIABILITIES				
Total liabilities	**$**	**0**	$	0
NET POSITION				
Restricted for other postemployment benefits (OPEB)	**$**	**89,431**	$	109,743
Total net position	**$**	**89,431**	$	109,743
Total liabilities & net position	**$**	**89,431**	$	109,743

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, 2022 and 2021

	2022	2021
	(Thousands)	
ADDITIONS		
Employer contributions	**$ 9,578**	$ 7,691
Total employer contributions	**9,578**	7,691
Investment income (loss)		
Appreciation (depreciation) in fair value of investments	**(32,722)**	(4,147)
Interest	**2,832**	2,458
Net investment income (loss)	**(29,890)**	(1,689)
Total additions	**(20,312)**	6,002
DEDUCTIONS		
Total deductions	**0**	0
Change in net position	**(20,312)**	6,002
Net position - beginning of period	**109,743**	103,741
Total net position - ending	**$ 89,431**	$ 109,743

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 and wholesale water 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 constructions. Due to the adoption of GASB 89, *Accounting for Interest Cost Incurred Before the End of Construction Period*, interest is no longer capitalizable subsequent to 2020. Those 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 2022. 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,	**2022**	2021
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, and 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,	**2022**			2021		
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 439.5**	**$ 229.9**	**$ 669.4**	$ 427.5	$ 266.7	$ 694.2
Accretion expense	**12.4**	**4.3**	**16.7**	12.0	4.8	16.8
Removal/Settlements	**-**	**(55.6)**	**(55.6)**	-	(41.6)	(41.6)
Balance as of December 31,	**$ 451.9**	**$ 178.6**	**$ 630.5**	$ 439.5	$ 229.9	$ 669.4
Asset Retirement Cost (ARC):	**$ 96.5**	**$ 170.4**	**$ 266.9**	$ 96.5	$ 170.4	$ 266.9
Regulatory Asset - ARO	**$ 461.7**	**$ 177.0**	**$ 638.7**	$ 444.7	$ 228.1	$ 672.8

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, 2022 and 2021 were $17.0 million and $11.9 million, respectively, which are included as part of electric operating expenses, and represent a cumulative amount reported to date based on the use of 18% of the total permitted capacity of the Cross Landfill Area 1B ,76% of the total permitted capacity of the Winyah Landfill Area 1, and 7% of Winyah Landfill Area 2. The Authority will recognize the remaining estimated cost of closure and post-closure care for these landfill areas of $15.9 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 2022. The landfill closure and post-closure care liabilities at December 31, 2022 and 2021 were $10.9 million for both years. 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 2026. Future, already permitted landfill cells will be 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 2022, 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 are 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 2022 or 2021.

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. Accordingly, $33,000 was amortized in 2022. The remaining balance outstanding at December 31, 2022 was $37.1 million.

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, $55.5 million and $6.5 million was amortized in 2022 and 2021, respectively. The remaining balance outstanding at December 31, 2022 was $3.642 billion.

Deferred Inflows of Resources – Toshiba Settlement
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 2022 and 2021 $9.1 million and $45.3 million, respectively was amortized. The remaining balance outstanding at December 31, 2022 was $242.0 million.

Regulatory Asset - Cook Settlement Exceptions
On June 27, 2022, the Board authorized the use of regulatory accounting for the 2020 & 2021 Cook Rate Freeze Exceptions Costs (See Note 5 - *Cook Settlement as to Rates*) identified in the Authority's 2020 & 2021 Annual Cook Compliance Reports allowing the Authority to create a regulatory asset (the "Cook Settlement Exceptions Regulatory Asset") and to defer recognition on its Statement of Revenues, Expenses and Changes in Net Position of the expenses associated with those exceptions that qualify for such regulatory accounting treatment, including any future adjustments to the amount of such expenses (the "Cook Deferred Expenses"). As of December 31, 2022, the Authority recorded a total of $358.6 million of Cook Deferred Expenses in the regulatory account associated with the Cook Settlement Exception Regulatory Asset.

Regulatory Asset - OPEB
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 is being 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, 2022 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, 2022 and 2021 were as follows:

Years Ended December 31,	**2022**	2021
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,	**2022**	2021
	(Thousands)	
TEA Investment:		
Balance as of January 1,	**$ 21,834**	$ 9,422
Reduction to power costs and increases in electric revenues	**253,150**	95,272
Less: Distributions from TEA	**249,049**	82,860
Balance as of December 31,	**$ 25,935**	$ 21,834
Due To/Due From TEA:		
Payable to	**$ 104,645**	$ 66,037
Receivable from	**$ 21,581**	$ 11,735

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, 2022, the trade guarantees are an amount not to exceed Santee Cooper's share of approximately $111.2 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, 2022 and 2021 were as follows:

Years Ended December 31,	**2022**	2021
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, 2022 and 2021 was approximately $121,900 and $122,525, respectively.

N - Deferred Outflows / Deferred Inflows of Resources - In addition to assets, the Statements of Net Position report 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) deferred outflows – OPEB; (3) Regulatory – asset retirement obligation; (4) accumulated decrease in fair value of hedging derivatives; and (5) unamortized loss on refunded and defeased debt.

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) deferred inflows – OPEB; (3) accumulated increase in fair value of hedging derivatives; (4) nuclear decommissioning costs; and (5) Regulatory inflows - Toshiba settlement.

The following table summarizes the Authority's total deferred items:

Years Ended December 31,		2022		2021
		(Thousands)		
Deferred outflows of resources	**$**	**976,711**	$	872,566
Deferred inflows of resources	**$**	**723,093**	$	700,143

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, 2022 and 2021 is below:

Cash Flow Hedges and Summary of Activity

Years Ended December 31,			2022		2021
	Account Classification		(Millions)		
Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**151.9**	$	91.1
Heating oil	Regulatory assets/liabilities		**29.9**		15.9
Changes in Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**60.8**	$	97.2
Heating oil	Regulatory assets/liabilities		**14.1**		13.6
Recognized Net Gains (Losses)					
Natural gas	Operating expense-fuel	**$**	**119.2**	$	34.2
Heating oil	Operating expense-fuel		**14.6**		5.5
Realized But Not Recognized Net Gains (Losses)					
Natural gas	Regulatory assets/liabilities	**$**	**1.3**	$	2.8
Heating oil	Regulatory assets/liabilities		**1.1**		0.5
Notional					
			MMBTUs		
Natural gas			**130,132**		138,912
			Gallons (000s)		
Heating oil			**26,208**		16,037
Maturities					
Natural gas			**Jan 2023-Dec 2026**		Jan 2022-Dec 2026
Heating oil			**Jan 2023-Dec 2025**		Jan 2022-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 $13.3 million in 2022 and $14.5 million in 2021.

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 municipal and retail fuel adjustments are under the rate freeze schedules (See Note 10 - Legal Matters, Recently Settled Litigation Matters, *Jessica S. Cook et al. v. The Authority* on page, 81 for additional information). 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.

Rates to Central are determined in accordance with the cost of service methodology contained in the Coordination 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 Agreement 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 Agreement (See Note 5 – *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 2022 and 2021 totaled approximately $17.7 million and $17.1 million, respectively.

S - New Accounting Standards –

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 87	**Leases**	Reviewed and effect deemed immaterial
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**	Reviewed and no action taken
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	Reviewed and no action taken
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**	Reviewed and deemed not applicable in 2022
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.	
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**	Reviewed and no action taken
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.	
Statement No. GASB 98	**The Annual Comprehensive Financial Report**	Reviewed and no action taken
Issue Date: October 2021	Effective for Periods Beginning After: December 15, 2021	
Description:	This Statement establishes the term annual comprehensive financial report and its acronym ACFR. That new term and acronym replace instances of comprehensive annual financial report and its acronym in generally accepted accounting principles for state and local governments. This Statement was developed in response to concerns raised by stakeholders that the common pronunciation of the acronym for comprehensive annual financial report sounds like a profoundly objectionable racial slur. This Statement's introduction of the new term is founded on a commitment to promoting inclusiveness. One of the principles guiding the Board's setting of standards for accounting and financial reporting is the assessment of expected benefits and perceived costs. The Board strives to determine that its standards address significant user needs and that the costs incurred through the application of its standards, compared with possible alternatives, are justified when compared to the expected overall public benefit	
Statement No. GASB 99	**Omnibus 2022**	Under review
Issue Date: June 2022	Effective date: The requirements of this Statement are effective as follows: • The requirements related to extension of the use of LIBOR, accounting for SNAP distributions, disclosures of nonmonetary transactions, pledges of future revenues by pledging governments, clarification of certain provisions in Statement 34, as amended, and terminology updates related to Statement 53 and Statement 63 are effective upon issuance. • The requirements related to leases, PPPs, and SBITAs are effective for fiscal years beginning after June 15, 2022, and all reporting periods thereafter. • The requirements related to financial guarantees and the classification and reporting of derivative instruments within the scope of Statement 53 are effective for fiscal years beginning after June 15, 2023, and all reporting periods thereafter	
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 (1) practice issues that have been identified during implementation and application of certain GASB Statements and (2) accounting and financial reporting for financial guarantees. The practice issues addressed by this Statement are as follows:	

- Classification and reporting of derivative instruments within the scope of Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*, that do not meet the definition of either an investment derivative instrument or a hedging derivative instrument
- Clarification of provisions in Statement No. 87, *Leases*, as amended, related to the determination of the lease term, classification of a lease as a short-term lease, recognition and measurement of a lease liability and a lease asset, and identification of lease incentives
- Clarification of provisions in Statement No. 94, *Public-Private and Public-Public Partnerships and Availability Payment Arrangements*, related to (a) the determination of the public-private and public-public partnership (PPP) term and (b) recognition and measurement of installment payments and the transfer of the underlying PPP asset
- Clarification of provisions in Statement No. 96, *Subscription-Based Information Technology Arrangements*, related to the subscription-based information technology arrangement (SBITA) term, classification of a SBITA as a short-term SBITA, and recognition and measurement of a subscription liability
- Extension of the period during which the London Interbank Offered Rate (LIBOR) is considered an appropriate benchmark interest rate for the qualitative evaluation of the effectiveness of an interest rate swap that hedges the interest rate risk of taxable debt
- Accounting for the distribution of benefits as part of the Supplemental Nutrition Assistance Program (SNAP)
- Disclosures related to nonmonetary transactions
- Pledges of future revenues when resources are not received by the pledging government
- Clarification of provisions in Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*, as amended, related to the focus of the government-wide financial statements
- Terminology updates related to certain provisions of Statement No. 63, Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position
- Terminology used in Statement 53 to refer to resource flows statements.

Statement No. GASB 100	**Accounting Changes and Error Corrections – an amendment of GASB Statement No. 62**	Under review
Issue Date: June 2022	Effective for periods beginning after June 15, 2023	
Description:	The primary objective of this Statement is to enhance accounting and financial reporting requirements for accounting changes and error corrections to provide more understandable, reliable, relevant, consistent, and comparable information for making decisions or assessing accountability. This Statement defines *accounting changes* as changes in accounting principles, changes in accounting estimates, and changes to or within the financial reporting entity and describes the transactions or other events that constitute those changes. As part of those descriptions, for (1) certain changes in accounting principles and (2) certain changes in accounting estimates that result from a change in measurement methodology, a new principle or methodology should be justified on the basis that it is preferable to the principle or methodology used before the change. That preferability should be based on the qualitative characteristics of financial reporting—understandability, reliability, relevance, timeliness, consistency, and comparability. This Statement also addresses corrections of errors in previously issued financial statements.	
Statement No. GASB 101	**Compensated Absences**	Under review
Issue Date: June 2022	Effective for periods beginning after December 15, 2023	
Description:	The objective of this Statement is to better meet the information needs of financial statement users by updating the recognition and measurement guidance for compensated absences. That objective is achieved by aligning the recognition and measurement guidance under a unified model and by amending certain previously required disclosures. This Statement requires that liabilities for compensated absences be recognized for (1) leave that has not been used and (2) leave that has been used but not yet paid in cash or settled through noncash means. A liability should be recognized for leave that has not been used if (a) the leave is attributable to services already rendered, (b) the leave accumulates, and (c) the leave is more likely than not to be used for time off or otherwise paid in cash or settled through noncash means. Leave is attributable to services already rendered when an employee has performed the services required to earn the leave. Leave that accumulates is carried forward from the reporting period in which it is earned to a future reporting period during which it may be used for time off or otherwise paid or settled. In estimating the leave that is more likely than not to be used or otherwise paid or settled, a government should consider relevant factors such as employment policies related to compensated absences and historical information about the use or payment of compensated absences. However, leave that is more likely than not to be settled through conversion to defined benefit postemployment benefits should not be included in a liability for compensated absences. This Statement requires that a liability for certain types of compensated absences—including parental leave, military leave, and jury duty leave—not be recognized until the leave commences. This Statement also requires that a liability for specific types of compensated absences not be recognized until the leave is used	

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,		**2022**		2021
		(Millions)		
CTBR regulatory asset:				
Balance	**$**	**222.0**	$	222.9
CTBR expense/(reduction to expense):				
Net expense	**$**	**1.0**	$	(3.1)

Note 3 – Capital Assets

Capital asset activity for the years ended December 31, 2022 and 2021 was as follows:

		Beginning Balances		**Increases**		**Decreases**		**Ending Balances**
				Year 2022 (Thousands)				
Utility plant	**$**	**8,800,734**	**$**	**287,888**	**$**	**(68,214)**	**$**	**9,020,408**
Long lived assets-asset retirement cost		**266,981**		**0**		**0**		**266,981**
Accumulated depreciation		**(4,422,072)**		**(273,646)**		**75,854**		**(4,619,864)**
Total utility plant-net		**4,645,643**		**14,242**		**7,640**		**4,667,525**
Construction work in progress		**331,065**		**171,228**		**(287,920)**		**214,373**
Other physical property-net		**26,492**		**-**		**(770)**		**25,722**
Totals	**$**	**5,003,200**	**$**	**185,470**	**$**	**(281,050)**	**$**	**4,907,620**

		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

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,	**2022**			2021		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 58,773**	**$ 10,997**	**$ 69,770**	$ 68,412	$ 34,544	$ 102,956
Debt Reduction	**2,463**	**12,867**	**15,330**	6,123	89,490	95,613
Funds from Taxable Borrowings	**23,215**	**35,911**	**59,126**	15,655	-	15,655
General Improvement	**3**	**-**	**3**	9	-	9
Internal Nuclear Decommissioning Fund	**93**	**79,204**	**79,297**	268	92,144	92,412
Nuclear Fuel	**993**	**-**	**993**	9,408	4,000	13,408
Revenue and Operating	**179,983**	**250**	**180,233**	135,544	4,248	139,792
Contingency / Sub-Revenue	**-**	**-**	**-**	39,817	30,160	69,977
Special Reserve	**33,761**	**24,338**	**58,099**	24,251	49,039	73,290
Total	**$ 299,284**	**$ 163,567**	**$ 462,851**	$ 299,487	$ 303,625	$ 603,112
Current Restricted:						
Debt Service Funds	**$ 34,440**	**$ 26,713**	**$ 61,153**	$ 15,009	$ 32,529	$ 47,538
Funds from Tax-exempt Borrowings	**15,835**	**408,342**	**424,177**	18,721	127,504	146,225
Special Reserve and Other	**2,900**	**24,462**	**27,362**	2,900	22,310	25,210
Total	**$ 53,175**	**$ 459,517**	**$ 512,692**	$ 36,630	$ 182,343	$ 218,973
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 373**	**$ 123,778**	**$ 124,151**	$ 269	$ 152,254	$ 152,523
Total	**$ 373**	**$ 123,778**	**$ 124,151**	$ 269	$ 152,254	$ 152,523
TOTAL FUNDS	**$ 352,832**	**$ 746,862**	**$ 1,099,694**	$ 336,386	$ 638,222	$ 974,608

Cash and investments as of December 31, consisted of the following:	2022	2021
Cash/Deposits	**$ 32,187**	$ 88,312
Investments	**1,067,507**	886,296
Total cash and investments	**$ 1,099,694**	$ 974,608

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,	**2022**	2021
Total Portfolio	(Billions)	
Total investments	**$ 1.1**	$ 0.9
Purchases	**28.5**	28.2
Sales	**28.3**	28.0
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	**$ 203.1**	$ 244.7
Purchases	**140.7**	185.3
Sales	**133.6**	177.8
Unrealized holding gain/(loss)	**(48.7)**	(8.8)
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, 2022 and 2021, 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, 2022 and 2021, 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, 2022 and 2021, 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, 2022 and 2021 were as follows:

Security Type / Issuer	Fair Value 2022	Fair Value 2021
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 187,998**	$ 119,766
Federal National Mortgage Association	**Less than 5%**	Less than 5%
Federal Farm Credit Bank	**122,721**	278,431
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, 2022 and 2021:

		Investment Maturities as of December 31, 2022			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
		(Thousands)			
Collateralized Deposits	**$ 143,793**	**$ 143,543**	**$ 250**	**$ 0**	**$ 0**
Repurchase Agreements	**100,000**	**100,000**	**0**	**0**	**0**
Federal Agency Discount Notes	**112,492**	**112,492**	**0**	**0**	**0**
Federal Agency Securities	**237,561**	**62,684**	**30,945**	**56,989**	**86,943**
US Treasury Bills, Notes and Strips	**473,661**	**232,186**	**222,339**	**6,851**	**12,285**
	$ 1,067,507	**$ 650,905**	**$ 253,534**	**$ 63,840**	**$ 99,228**

		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
	$ 886,296	$ 586,030	$ 91,570	$ 78,648	$ 130,048

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 $11.2 million par in government agency zero coupon securities in the two portfolios ranging in maturity from May 15, 2023 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 none of the invested decommissioning funds will be needed prior to 2062. 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, 2022 and 2021:

		Level		
2022	**Total**	**1**	**2**	**3**
		(Thousands)		
Collateralized Deposits	**$ 143,793**	**$ 0**	**$ 143,793**	**$ 0**
Repurchase Agreements	**100,000**	**0**	**100,000**	**0**
Federal Agency Discount Notes	**112,492**	**0**	**112,492**	**0**
Federal Agency Securities	**237,561**	**0**	**237,561**	**0**
US Treasury Bills, Notes and Strips	**473,661**	**0**	**473,661**	**0**
	$ 1,067,507	**$ 0**	**$ 1,067,507**	**$ 0**

		Level		
2021	Total	1	2	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

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 results 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, 2022 and 2021, 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, 2022 and 2021, 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, 2022 and 2021, 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, 2022 and 2021 were as follows:

Security Type / Issuer	Fair Value	
	2022	2021
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 20,813**	$ 23,122
Federal National Mortgage Association	**Less than 5%**	Less than 5%
Federal Farm Credit Bank	**29,008**	38,359
Federal Home Loan Mortgage Corp	**12,954**	18,116

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, 2022 and 2021:

		Investment Maturities as of December 31, 2022			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
		(Thousands)			
Federal Agency Securities	**65,811**	**0**	**999**	**0**	**64,812**
Government Securities	**19,426**	**0**	**0**	**0**	**19,426**
	$ 85,237	**$ 0**	**$ 999**	**$ 0**	**$ 84,238**

		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

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, 2022 and 2021:

		Level		
2022	**Total**	**1**	**2**	**3**
		(Thousands)		
Federal Agency Securities	**65,811**	**0**	**65,811**	**0**
Government Securities	**19,426**	**0**	**19,426**	**0**
	$ 85,237	**$ 0**	**$ 85,237**	**$ 0**

		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

Note 5 – Cook Settlement as to Rates

On July 31, 2020, the Board authorized management to implement the terms of the Cook Settlement Agreement which provides, in part, for Settlement Rates (defined below) that are effective beginning in August of 2020 and continuing (i) for the customers other than Central Electric Power Cooperative, Inc. ("Central") whose rates are subject to the Rate Freeze, through all bills rendered on or before January 15, 2025, and (ii) for Central, through service rendered on or before December 31, 2024. The respective periods are referred to as the "Rate Freeze Period."

The rate freeze agreed to by the Authority is consistent with rates and the rate stabilization period that was set forth in the Authority's original plan for reform, restructuring, and changes in operations submitted to the South Carolina Department of Administration ("DOA") in November 2019 as part of the State's evaluation of whether or not to sell some or all of the Authority. The Authority's plan was subsequently modified by the Authority following discussions with the DOA and Central. On January 24, 2020, the Authority submitted its plan dated January 3, 2020 to the South Carolina General Assembly pursuant to Act No. 95 of 2019 (the "2019 Reform Plan"). The 2019 Reform Plan identified a series of changes to the Authority's generation and transmission systems as well as expense management and other initiatives intended to achieve cost savings and optimize efficient operations.

The 2019 Reform Plan also included a financial forecast that projected future revenue and expenses. The forecast projected three major "adjustments" to the primary rate components (energy and demand charges) impacting most customers: (1) the fuel adjustment, (2) demand sales adjustment, and (3) economic development sales adjustment. The purpose of these adjustments is to "true up" their values to "actual" base rates. Under normal conditions these values are calculated and then applied to customer bills monthly. As part of the Cook Settlement Agreement, however, these values for the impacted customers are fixed through the Rate Freeze Period.

In accordance with the terms of the Cook Settlement Agreement, the Board authorized management to freeze certain 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 Rate Freeze Period (the "Settlement Rates"). The Settlement Rates impact a majority of the Authority's customers and freeze 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 Rates suspend the variability 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 frozen for almost all residential and commercial customers participating in the Settlement Rates, as well as industrial customers served under the Schedule L rate and the Interruptible and Economy Power Optional riders. The Settlement Rates under Schedule B also apply to customers with contractual rates based on the Municipal Street Lighting rate (ML), the cities of Bamberg, Georgetown, and Seneca.

As part of the Cook Settlement Agreement, the Authority agreed not to defer any costs and expenses incurred or otherwise appropriately attributable to any year during the Rate Freeze Period to any other year or years during or after the Rate Freeze Period, provided, however, that the Authority may defer to rates charged in years after the Rate Freeze Period just and reasonable costs and expenses incurred during the Rate Freeze Period directly resulting from the specific circumstances or events as enumerated in the Agreement (the "Cook Rate Freeze Exceptions"). The Authority must identify any Cook Rate Freeze Exceptions in annual reports provided by the Authority to the Court of Common Pleas for the Thirteenth Judicial Circuit.

In April 2021, the Authority filed its first Annual Cook Compliance Report which identifies three categories of costs and expense occurring during 2020 that qualify as Cook Rate Freeze Exceptions, including (i) $5.2 million resulting from a change in law due to the COVID-19 pandemic, (ii) $1.2 million resulting from named storm Hurricane Isaias; and (iii) $13.3 million attributed to Central Load Deviations.

In April 2022, the Authority filed its second Annual Cook Compliance Report which identifies eight situations that fall within four categories of costs and expenses occurring during 2021 that qualify as Cook Rate Freeze Exceptions. The four categories include (i) $11.9 million resulting from various changes in law; (ii) $175,000 resulting from named Tropical Storm Elsa; (iii) $43.4 million resulting from the coal mine fire and subsequent change in law that required the mine to remain closed ($37.8 million) and the fire and failure of equipment at Virgil C. Summer Nuclear Generating Station Unit 1 ($5.6 million); and (iv) $15.4 million attributable to Central Load Deviations (collectively, the "2021 Cook Rate Freeze Exceptions").

On June 27, 2022, the Board authorized the use of regulatory accounting for the 2020 & 2021 Cook Rate Freeze Exceptions Costs identified in the Authority's 2020 & 2021 Annual Cook Compliance Reports allowing the Authority to create a regulatory asset -and to defer recognition on its Statement of Revenues, Expenses and Changes in Net Position of the expenses associated with those exceptions that qualify for such regulatory accounting treatment, including any future adjustments to the amount of such expenses.

The following reflects the Cook Deferred Expenses recorded as the Cook Exceptions Regulatory Asset as of December 31, 2022:

Year Ending December 31:		
Load Exception – Certain deviations in Central's actual loads	$	13,169,774
Load Exception Interest – Certain deviation in Central's actual loads		8,398,351
Foresight Local Mine Fire – Subsequent change in law that required the mine to stay closed		318,533,013
Change in Law		12,920,563
VCS 1 Fire		4,824,460
Named Storm Events – Hurricane Isaias and Tropical Storm Elsa		759,218
Total Regulatory Asset	$	358,605,379

Note 6 – Long -Term Debt

Debt Outstanding

The Authority's long-term debt at December 31, 2022 and 2021 consisted of the following:

	2022	2021	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2056)				
2009 Taxable Series C	**1,575**	1,830	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
2012 Taxable Series E	**183,378**	230,460	3.572-4.551	P&I Plus Make-Whole Premium
2013 Tax-exempt Series A	**107,560**	152,655	5.00-5.50	100
2013 Tax-exempt Refunding Series B	**224,525**	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	**275,730**	506,765	5.00-5.50	100
2014 Tax-exempt Series A	**294,970**	525,000	5.00-5.50	100
2014 Tax-exempt Refunding Series B	**22,380**	42,275	5.00	100
2014 Tax-exempt Refunding Series C	**351,625**	628,260	3.00-5.50	100
2014 Taxable Refunding Series D	**24,970**	31,795	2.906-3.606	P&I Plus Make-Whole Premium
2015 Tax-exempt Refunding Series A	**363,410**	558,925	3.00-5.00	100
2015 Tax-exempt Refunding Series B	**23,725**	64,870	5.00	Non-callable
2015 Tax-exempt Refunding Series C	**0**	19,940	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	**108,125**	300,000	5.25	100
2016 Tax-exempt Refunding Series A	**459,115**	465,210	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	**50,360**	52,400	3.00-5.00	100
2016 Taxable Series D	**0**	174,980	2.380	P&I Plus Make-Whole Premium
2019 Tax-exempt Refunding Series A[4]	**143,200**	143,200	Variable Rate	100
2020 Tax-exempt Refunding Series A	**333,710**	337,145	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	**144,995**	145,735	4.00-5.00	100
2021 Tax-exempt Series B	**280,170**	284,555	4.00-5.00	100
2022 Tax-exempt Refunding Series A	**930,990**	0	4.00-5.00	100
2022 Tax-exempt Refunding Series B	**352,201**	0	3.00-5.00	100
2022 Tax-exempt Refunding Series C	**36,640**	0	5.00-5.50	100
2022 Taxable Refunding Series D	**134,850**	0	5.724-6.436	P&I Plus Make-Whole Premium
2022 Tax-exempt Series E	**390,000**	0	5.00-5.75	100
2022 Taxable Series F	**60,000**	0	5.724-6.447	P&I Plus Make-Whole Premium
Total Revenue Obligations	**6,886,291**	6,642,817		
Direct Placement Long-Term Revolving Credit Agreement: (matures through 2029)	**219,460**	19,000	N/A	N/A
Less: Current Portion - Long-term Debt	**39,525**	107,791		
Total Long-term Debt - (Net of current portion)	**$7,066,226**	$6,554,026		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2022.
(2) Call Price may only apply to certain maturities outstanding at December 31, 2022.
(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, 2022 and 2021 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 2022 (Thousands)				
Revenue Obligations	**$ 6,642,817**	**$ 1,904,681**	**$ (1,661,207)**	**$ 6,886,291**	**$ 39,525**	**$ 6,846,766**	**$ 507,324**	**$ 7,354,090**
Direct Placement Long-Term Revolving Credit Agreement	**22,211**	**219,460**	**(22,211)**	**219,460**	**0**	**219,460**	**0**	**219,460**
Totals	**$ 6,665,028**	**$ 2,124,141**	**$ (1,683,418)**	**$ 7,105,751**	**$ 39,525**	**$ 7,066,226**	**$ 507,324**	**$ 7,573,550**
				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

Summary of Long-Term Principal and Interest

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

	Revenue Obligations	Long-Term Revolving Credit Agreements	Total Principal	TOTAL Interest [1]	TOTAL
Year Ending December 31,			(Thousands)		
2023	$ 39,525	$ 454	$ 39,979	$ 337,191	$ 377,170
2024	119,266	458	119,724	336,164	455,888
2025	129,905	200,838	330,743	330,994	661,737
2026	151,747	1,934	153,681	316,458	470,139
2027	151,101	1,957	153,058	309,503	462,561
2028-2032	979,786	10,116	989,902	1,430,798	2,420,700
2033-2037	1,141,165	3,703	1,144,868	1,192,327	2,337,195
2038-2042	1,106,942	0	1,106,942	918,439	2,025,381
2043-2047	1,240,683	0	1,240,683	634,406	1,875,089
2048-2052	1,260,266	0	1,260,266	317,119	1,577,385
2053-2056	565,905	0	565,905	51,813	617,718
Total	$ 6,886,291	$ 219,460	$ 7,105,751	$ 6,175,212	$ 13,280,963

[1] Does not reflect impact of subsidy interest payments on 2010 Taxable C (Build America Bonds). Years 2023-2037 include projected interest for Long-Term Revolving Credit Agreements and Variable Rate Debt.

Summary of Refunded and Defeased Debt and Unamortized Losses

Refunded and defeased debt, original loss on refunding and the unamortized loss at December 31, 2022 are as follows:

Refunding Description		Refunded/Defeased Debt		Outstanding	Original Loss	Unamortized Loss
		(Thousands)			(Thousands)	
Feb 2012 Defeasance	$	5,615	2003 Refunding Series A	$ 0	$749	$338
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	5,437
2013 Refunding Series C	$	35,584	2003 Refunding Series A			
		97,695	2008 Series B	0	4,601	2,595
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	10,804
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	4,922
2015 Refunding Series B	$	78,150	2005 Refunding Series C	0	4,987	403
2015 Series E	$	100,000	Barclays Revolving Credit Agreement	0	89	26
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	30,704
2016 Refunding Series B	$	97,715	2009 Series E	0	12,873	9,004

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

Refunding Description		Refunded/Defeased Debt		Outstanding	Original Loss	Unamortized Loss
		(Thousands)			(Thousands)	
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	498
2020 Refunding Series A	$	5,510	2009 Series A	0	77	4
2021 CP Partial Redemption	$	17,495	2019 Refunding Series A	0	846	728
2021 Refunding Series A	$	135,855	2011 Refunding Series C			
		38,575	2012 Refunding Series A	0	344	306
2022 Refunding Series A & B		45,095	2013 Series A			
		164,205	2013 Refunding Series B			
		231,035	2013 Series E			
		230,030	2014 Series A			
		19,895	2014 Refunding Series B			
		232,260	2014 Refunding Series C			
		173,315	2015 Series A			
	$	191,875	2015 Series E	0	124,366	119,671
Total				$ 0	$ 275,616	$ 185,440

(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, 2022 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
12/2022 Cash Defeasance	$	23,541	2012 Series E			
		24,915	2014 Refunding Series C			
		2,000	2014 Refunding Series D			
		17,720	2015 Refunding Series A			
		20,505	2015 Refunding Series B			
		580	2020 Refunding Series A	$ 89,309		$ 89,261
Total				$ 196,578		$ 189,261

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 2021 current portion of long-term debt showing the amounts paid as debt service in 2022.

Analysis of December 31, 2021 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from Revenues	$ 106,906
2021 maturities defeased	885
Total	$ 107,791

Reconciliations of Interest Charges

Years Ended December 31,		2022		2021
		(Thousands)		
Reconciliation of interest cost to interest expense:				
Total interest cost	$	**302,680**	$	313,177
Interest charged to fuel expense		**0**		(2)
Total interest expense on long-term debt	**$**	**302,680**	$	313,175
Reconciliation of interest cost to interest payments:				
Total interest cost	$	**302,680**	$	313,177
Accrued interest-current year		**(40,456)**		(38,324)
Accrued interest-prior year		**38,324**		37,919
Interest released by refundings		**(17,202)**		(2,153)
Regulatory Assets – Cook Settlement Exceptions		**8,398**		-
Year-end manual accrual		**(186)**		-
Total interest payments on long-term debt	**$**	**291,558**	$	310,619

Debt Service Coverage

Years Ended December 31,	**2022**	2021
	(Thousands)	
Operating revenues	**$ 1,949,050**	$ 1,765,785
Interest and investment revenue	**6,751**	2,075
Total revenues and income	**1,955,801**	1,767,860
Operating expenses (1)	**(1,670,010)**	(1,496,286)
Depreciation	**269,073**	259,075
Total expenses	**(1,400,937)**	(1,237,211)
Funds available for debt service prior to distribution to the State	**554,864**	530,649
Distribution to the State	**(17,675)**	(17,135)
Funds available for debt service after distribution to the State	**$ 537,189**	$ 513,514
Debt Service on Accrual Basis:		
Principal on long-term debt	**$ 125,746**	$ 101,786
Interest on long-term debt (2)	**302,680**	313,175
Long-term debt service paid from Revenues	**428,426**	414,961
Commercial paper and other principal and interest	**9,208**	8,584
Total debt service paid from Revenues	**$ 437,634**	$ 423,545
Debt Service Coverage Ratio:		
Excluding commercial paper and other:		
Prior to distribution to the State, including Cook Deferred Expenses	**1.29**	1.27
After distribution to the State, including Cook Deferred Expenses	**1.25**	1.23
After distribution to the State, excluding Cook Deferred Expenses	**0.42**	-
Including commercial paper and other:		
Prior to distribution to the State, including Cook Deferred Expenses	**1.26**	1.25
After distribution to the State, including Cook Deferred Expenses	**1.22**	1.21
After distribution to the State, excluding Cook Deferred Expenses	**0.41**	-

(1) Operating expenses were reduced by $350.3 million due to the deferral of the Cook Deferred Expenses to the Cook Settlement Exceptions Regulatory Asset.

(2) 2022 Interest on long-term debt was reduced by $8.4 million due to the deferral of the Cook Deferred Expenses to the Cook Settlement Exceptions Regulatory Asset.

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 $6.7 billion and $7.7 billion at December 31, 2022 and 2021, respectively.

Bond Market Transactions

Bond market transactions for the year ended December 31, 2022 were as follows:

Revenue Obligations, 2022 Tax-Exempt Refunding Series A and Tax-Exempt Refunding Series B	**Par Amount: $1,283,191,000**	**Date Authorized: February 9, 2022**

Summary: - Issued on February 23, 2022 at an all-in true interest rate of 3.311 percent
- Matures December 1, 2055

Revenue Obligations, 2022 Tax-Exempt Refunding Series C, Taxable Refunding Series D, Tax-Exempt Improvement Series E, and Taxable Improvement Series F	**Par Amount: $621,490,000**	**Date Authorized: November 9, 2022**

Summary: - Issued on November 15, 2022 at an all-in true interest rate of 5.550 percent
- Matures December 1, 2043

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

Revenue Obligations, 2021 Tax-Exempt Refunding Series A and Tax-Exempt Improvement Series B	Par Amount: $430,290,000	Date 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

Debt Covenant Compliance

As of December 31, 2022, and 2021, 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,	**2022**	2021
Outstanding Revenue Obligations	**$ 6.9 Billion**	$ 6.6 Billion
Estimated remaining interest payments	**$ 6.1 Billion**	$ 6.2 Billion
Issuance years (inclusive)	**2009 through 2022**	2009 through 2021
Maturity years (inclusive)	**2023 through 2056**	2022 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 7 – 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. As of December 31, 2022, seven percent 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,	**2022**	2021
Commercial paper outstanding (000's)	**$ 118,246**	$ 120,832
Effective interest rate (at December 31)	**4.43%**	.15%
Average annual amount outstanding (000's)	**$ 120,086**	$ 167,247
Average maturity	**47 Days**	63 Days
Average annual effective interest rate	**1.76%**	.13%

As of December 31, 2022, 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. The unused available capacity was $181.8 million as of December 31, 2022.

As of December 31, 2022, 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 March 1, 2022, amended on August 12, 2022 and expires on March 20, 2026. The unused available capacity was $121.9 million.

As of December 31, 2022, the Authority had a Revolving Credit Agreement with J.P. Morgan Chase Bank, N.A. for $200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on December 28, 2021,amended on July 28, 2022 and expires on December 27, 2024. The unused available capacity on this line was $121.7 million as of December 31, 2022.

As of December 31, 2022, 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 June 30, 2022 and expires June 28, 2024. The unused available capacity on this line was $200.0 million as of December 31, 2022.

As of December 31, 2022, the Authority had a Revolving Credit Agreement with Wells Fargo Bank, N.A. for $100.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on March 25, 2022, amended on August 12, 2022 and expires on March 25, 2025. The unused available capacity on this line was $36.9 million as of December 31, 2022.

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 (unless such acceleration is waived by the lender where applicable). The RCAs also contain provisions permitting the applicable lender upon an event of default to terminate its commitment to advance funds to make loans under the Agreement and its obligation to advance funds for loans under the Agreement and providing that such termination of its obligation to advance funds for loans under the 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 8 – Summer Nuclear Station

Summer Nuclear Unit 1

The Authority and DESC are parties to a joint ownership agreement providing that the Authority and DESC 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. DESC 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. On December 16, 2021, DESC filed an “Intent to Pursue License Renewal” notification to the NRC on behalf of itself and the Authority to extend the operating license from August 2042 to August 2062.

Authority's Share of Summer Nuclear - Unit 1

Years Ended December 31,	**2022**	2021
	(Millions)	
Plant balances before depreciation	**$ 792.5**	$ 825.4
Accumulated depreciation	**315.6**	340.2
Operation & maintenance expense	**75.6**	80.9

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.

DESC 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, DESC and the Authority are being reimbursed by DOE for a portion of ISFSI project costs. The DOE reimbursements to date equal approximately 75% of the total project costs, and the remaining reimbursement remains under dispute between DESC and the DOE.

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 assuming a SAFSTOR scenario and eighty year plant life, these funds, which total approximately $203.4 million (adjusted to market) at December 31, 2022, 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.

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 (SCANA’s subsidiary; SCANA was acquired by Dominion Energy on January 1, 2019 and established Dominion Energy South Carolina (DESC) as a wholly owned subsidiary of SCANA) (55% ownership interest) (together, the “Owners”).

On July 31, 2017, the Authority approved the wind-down and suspension of construction of the Summer Nuclear Units 2 and 3 at the Virgil C. Summer Nuclear Generating Station and the preservation and protection of the site and related components and equipment. The Authority had spent approximately $4.7 billion in construction and interest costs. Upon suspending construction, and in accordance with GASB No. 62, the Authority ceased capitalizing interest expense on the debt incurred to fund Summer Nuclear Units 2 and 3 as of July 31, 2017. With the exception of certain assets to be repurposed at Summer Nuclear Unit 1 or used to enhance the Authority’s transmission system, the fuel assets and non-fuel assets comprising Summer Nuclear Units 2 and 3 were determined in accordance with GASB No. 42 to be impaired.

Impairment and 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. 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 in accordance with GASB 42 to be impaired.

Regulatory Accounting for Summer Nuclear Units 2 and 3. 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 (i) a portion of post-suspension capitalized interest in the amount of $37.1 million to be amortized through November 2056 in order to align with the principal payments on the debt used to pay the interest and (ii) the recognition of income from the settlement agreement with the Toshiba Corporation ("Toshiba") relating to Toshiba's guaranty of certain payment obligations in respect of Summer Nuclear Units 2 and 3 (the "Toshiba Settlement Agreement") in the amount of $898.2 million, to be amortized over time to align with the manner in which the settlement proceeds are used to reduce debt service payments.

The following table summarizes the nuclear-related regulatory items:

Regulatory Item	Classification	Original Amount	2018 - 2022 Amortization	2018 - 2022 Changes	2022 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($ 529.3 million)	($40.2 million)	$ 3.642 billion
Nuclear post-suspension interest	Asset	$ 37.1 million	$ (33,000)		$ 37.1 million
Toshiba Settlement Agreement	Deferred Inflow	$ 898.2 million	($ 670.0 million)	$13.8 million	$ 242.0 million

Sales of Summer Nuclear Units 2 and 3 Assets. During calendar years 2018 - 2022, the Authority sold certain equipment and commodities to third parties. The Authority expects to use the net proceeds received from the sale of the nuclear-related equipment to pay down a portion of its outstanding debt. Through December 31, 2022, $78.6 million of materials have been sold.

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 2022, revenues pursuant to the Coordination Agreement were 55% of total sales of electricity, compared to 58% in 2021.

Central, under the terms of the Coordination Agreement, has the right to audit costs billed to it. 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 2022, operating revenues were reduced by $8.9 million related to prior years 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 Agreement (See Note 5 – *Cook Settlement as to Rates*) 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 2023 three-year capital budget is as follows:

Years Ending December 31,		2023		2024		2025
				(Millions)		
Environmental Compliance [1]	$	63.5	$	123.0	$	100.2
Load and Resource Plan [2]		0.6		1.0		218.1
Property Acquisition [2]		5.1		-		-
General System Improvements and Other [3]		284.6		270.5		258.4
Total Capital Budget [4]	$	353.8	$	394.5	$	576.7

Budget Assumptions:
[1] Project costs are associated with ash pond closures, solid waste landfill construction, and installation of wastewater treatment systems.
[2] Reflects future generation costs associated with the load and resource plan. "Property Acquisition" accounts for a purchase of land that can be resold if not used.
[3] Reflects ongoing improvements to existing generating resources and FERC Relicensing. "Other" includes Camp Hall and transmission improvements due to load growth.
[4] 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, 2022. 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)		
2023	$	349,704	$	246,829
2024		170,963		135,025
Total	$	520,667	$	381,854

[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, 2022:

Contracts with Minimum Fixed Payment Obligations[1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	13 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	3 Years	$ 44.1
2	2013	21 Years	434.9
1	2013	11 Years	5.0
1	2021	3 Years	16.7
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 DESC, 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 2023 and the total transmission obligations for 2024-2033. The wholesale customer obligations below represent projected transmission amounts through the term of the current contracts.

Transmission Obligations

	2023	2024-2033
	(Thousands)	
Other Customers	$ 5,841	$ 54,363
Total	$ 5,841	$ 54,363

Santee Cooper has executed four purchase power agreements with 5-year terms under the Public Utilities Regulatory Policies Act of 1978 (PURPA). Three projects associated with these agreements, each having a nameplate capacity of 75MW, have reached commercial operation. The project associated with Centerfield Solar, LLC, effective April 18, 2019, reached commercial operation in December 2020; the project associated with Gunsight Solar, LLC, effective April 30, 2019, reached commercial operation in December 2022; and the project associated with Allora Solar, LLC, effective May 19, 2020, reached commercial operation in February 2022. The project associated with Landrace Holdings, LLC, effective May 19, 2020, is expected to achieve commercial operation by Q3 2023.

In 2020, Santee Cooper issued a Request for Proposals for providing up to 500 MW of solar capacity and energy. Five contracts with terms ranging from 15-20 years were awarded, totaling 425 MW. Santee Cooper and Central each entered into separate purchased power agreements for their respective share of the output. In 2022, one of these purchase power agreements, totaling 75 MW, was terminated.

On November 1, 2022, the Authority filed with the Public Service Commission of South Carolina (Commission) an application for approval of the Authority's Competitive Procurement of Renewable Energy Program Pursuant to the Authority's requirements under Act 90 which requires the Authority to file for Commission approval of a program for the competitive procurement of energy, capacity, and environmental attributes from renewable energy facilities should Santee Cooper identify a need for new generation resources included in its Integrated Resource Plans or other planning processes. Subsequently, the Commission established a procedural schedule for this proceeding, which includes a hearing scheduled to begin June 12, 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 Unit 1. As of December 31, 2022, these contracts total approximately $77.0 million over the next 9 years.

The Authority successfully negotiated a Contractual Service Agreement with GEII, effective March 2016, that covers all units at Rainey Generating Station. 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 2027 and the Authority's estimated remaining commitment on the contract is $48.3 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 staged turbulent air reactor ("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 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 2022. 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 2022, 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, 2022. In addition, there have been no third-party claims regarding environmental damages for 2022 or 2021.

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,		**2022**		2021
		(Thousands)		
Unpaid claims and claim expense at beginning of year	**$**	**1,589**	$	1,554
Incurred claims and claim adjustment expenses:				
Add: Provision for current year events		**1,501**		1,166
Less: Payments for current and prior years		**406**		1,131
Total unpaid claims and claim expenses at end of year	**$**	**2,684**	$	1,589

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 $13.660 billion by the Price-Anderson Indemnification Act. This $13.660 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, DESC and the Authority maintain, with Nuclear Electric Insurance Limited ("NEIL"), $1.060 billion primary property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. DESC 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, DESC 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 $5.5 million for the primary policy and $1.3 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, 2022.

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 Electric Generating Units (EGUs), was vacated and remanded by the D.C. Circuit Court of Appeals on January 19, 2021. On June 30, 2022, the U.S. Supreme Court issued a landmark decision in West Virginia vs. EPA, which reversed the DC Circuit and held that Congress did not give the EPA authority under the CAA to regulate CO2 emissions based on generation shifting (outside the fence). The EPA plans to propose a new rule to regulate greenhouse gas (CO2) emissions from existing fossil fuel-fired EGUs by April 2023.

On October 23, 2015, the EPA finalized the new source performance standards ("NSPS") for CO2 emissions from new, reconstructed, and modified power plants, setting BSER for natural gas-fired and coal-fired EGUs. This rule required carbon capture, utilization, and storage ("CCUS") for coal-fired EGUs, effectively ending new construction of these units. On December 6, 2018, the EPA signed a proposed revision to the rule to set BSER for coal-fired EGUs to most efficient demonstrated steam cycle in combination with best operating practices, and removed the requirement for CCUS. The EPA is currently re-evaluating the limitations and requirements of this rule, to include lowering the CO2 emission limit for natural gas-fired EGUs, requiring co-firing with hydrogen, and/or use of CCUS, and plans to propose these revisions by April 2023. This revised standard could have a material impact on the Authority's ability to construct new or modify existing natural gas-fired power plants and will be evaluated once the limitations and requirements are available.

In September 2022, the EPA issued a notice requesting public comment on the regulations of greenhouse gases from new and existing fossil fuel-fired EGUs. Additionally, the EPA requested comment on the Mercury and Air Toxics Standard (MATS), specifically related to the 2020 residual risk and technology review of this regulation conducted by the Agency. The EPA is currently considering tightening of this standard based on findings of this review. The EPA described these actions as a "non-rulemaking" intended to collect public input in advance of the EPA's commencement of a formal rulemaking process. The Authority cannot currently predict the outcome or future scope, timing, and costs associated with any CO2 emissions requirements or MATS revisions.

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 announced its intention to implement a national program to evaluate and regulate a category of organic contaminants known as per- and polyfluoroalkyl 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 for additional monitoring of public water systems that require monitoring of such systems for 29 PFAS as unregulated contaminants. On March 14, 2023, the EPA announced a proposed rule to establish national drinking water standards for six PFAS known to occur in drinking water. The EPA will accept comments on the proposed rule following publication in the Federal Register and a final rule is anticipated by the end of 2023. 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 the Authority's transmission system 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.

The 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.

The EPA regulates oil spills prevention and preparedness under the CWA, Spill Prevention Control and Countermeasures ("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).

A revision to the NPDES Steam Electric Effluent Limitation Guidelines ("ELG") rule became effective on January 4, 2016. These revised ELGs included 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 related to leachate and legacy wastewater because it determined that these standards may not be sufficiently stringent. On October 13, 2020, the EPA published a revised ELG rule with lower mercury limits for Flue Gas Desulfurization ("FGD") wastewater along with some revisions related to bottom ash transport water. The 2020 rule also established a number of new subcategories. Beyond the standard best available technology (BAT) compliance option, subcategories potentially applicable for the Authority include those for retiring units and for facilities opting to comply via the voluntary incentive program (VIP) – each of these two alternate subcategories allow for an 8-year compliance schedule. 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 $153 million for FGD wastewater treatment, using the rule's BAT approach (physical-chemical and biological treatment). The Authority's board has voted to retire Winyah in the future and utilize the retirement exemption in the ELG rule, so costs of compliance with the ELG rule at Winyah are not expected to be significant under the Authority's current plans. 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 DHEC. While not final, draft permits for Cross and Winyah Generating Stations were put on public notice by DHEC in October 2021.

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. The Authority has submitted a notice of planned participation ("NOPP") for the voluntary incentive program (VIP) for Cross, based on treatment via membrane technology, and has requested parallel compliance paths in its permit.

This is intended to allow the BAT approach at Cross, while allowing the option to change to the VIP approach if that develops as a preferred option. The Authority has also submitted a NOPP for retirement at Winyah, which would allow an automatic transfer to the VIP option under the rule; in addition, the Authority has requested that language addressing automatic transfer to the VIP option be included in the final permit. There have been no further developments with the permits, so any additional requirements and associated costs are unknown. While the 2020 rule remains in force at this time, the EPA announced a new rulemaking initiative in the Federal Register ("FR") on August 3, 2021, stating its intention to reevaluate FGD wastewater and bottom ash transport water limits and compliance alternatives in a new rule. The FR statement announced the EPA's intention that permittees and state permitting authorities follow the 2020 rule until the new rule is published. EPA released a pre-publication version of a new proposed rule on March 8, 2023, which, if it were to be finalized without alteration, would require aggressive new treatment requirements similar to the 2020 rule's VIP subcategory. Santee Cooper is thoroughly analyzing this proposed rule and will take action to comply with the final rule, which is not expected to be released for at least another year. 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 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 have interpreted waters of the United States consistent with the pre-2015 regulation since that date. The EPA and Army Corps announced the signing of 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. A proposed rule was published December 7, 2021. The EPA's new interim definition of WOTUS passed the Office of Management Budget's ("OMB") interagency review on November 30, 2022 and was released as a pre-publication version on December 30, 2022, with the final rule published in the Federal Register on January 18, 2023. According to the pre-publication version, the new rule will establish a broader scope of jurisdiction under the Clean Water Act, resulting in more jurisdictional wetlands and fewer non-jurisdictional wetlands; the waste treatment exclusion was maintained. In addition to these regulatory actions, the U.S. Supreme Court is reviewing a lower court ruling (Sackett v. EPA) that may ultimately limit the agencies' plans for these rulemakings. This review is ongoing, with oral arguments complete as of early October 2022. At this time, it is not possible to determine the outcome of these various regulatory actions or to predict the changes that may occur as a result of the Supreme Court's future decision in Sackett v. EPA. The primary risk to the Authority is that it may require additional time and cost for new construction in the future.

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 the 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, the 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 cells 1, 2, and 3 at Winyah Generating Station have been in operation since November 2018 with cells 4 and 5 receiving approval from DHEC to operate on December 20, 2021. A permit to operate new cells 6 and 7 was issued on December 16, 2022, which completes the buildout of the landfill cells at Winyah. 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 June 2023 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 (expected July 2023) with procedures for CCR units to obtain permits in non-participating states, which currently 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 (expected August 2023). The CCR regulations and the EPA's interpretation of them have changed frequently and are expected to change in the ways described above. The Authority cannot predict other changes that the EPA may impose or the impacts upon the Authority's operations and financial results of these regulatory and interpretive changes until they are finalized and their impacts upon the Authority can be evaluated.

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, even at closed facilities, as legacy CCR impoundments. 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. Closure is in progress on all ponds and plans are being developed and implemented to facilitate closure of these remaining ponds by the deadlines established by the state and by the CCR Rule. The ponds will be closed through excavation and beneficial use of materials or through disposal in the industrial Class 3 solid waste landfills on-site at Cross and Winyah. For ponds subject to corrective action under the CCR Rule, closure by removal is the selected closure strategy and monitored natural attenuation is the selected groundwater remedy so that it meets groundwater protection standards. 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. Pond closure activities are expected to continue at least through 2031 and estimates of remaining costs are projected to be approximately $232 million between 2023 and 2031. This amount does not include possible groundwater corrective action for the Cross Gypsum Pond being conducted under the CCR Rule, for which additional costs, if any, are not yet known. 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 are 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 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)) at the Hidden Cove Marina, 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 informed the Authority that DHEC considers the Authority responsible for any necessary remediation activities, although the Authority reached a cost sharing agreement with the telecommunications company and lessee. 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 Excavation Corrective Action Plan and a Well Installation Plan on November 18, 2021. The Corrective Action Plan has been completed and quarterly groundwater monitoring is underway. The Corrective Action Plan was executed in 2022, and DHEC has indicated interest in closing this project out on the basis of sample data received since the site was excavated and backfilled. Therefore, costs for 2023 would come to approximately $15,000 for sampling, interactions with DHEC, and well abandonment. Santee Cooper has worked with other parties to share costs of the cleanup.

A separate 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 South Carolina Department of Transportation (SCDOT) right-of-way project, ARM Environmental reported a release at Packs Landing Marina on May 20, 2002 by submitting a Limited Phase II Subsurface Assessment for SCDOT Project #99-188D. The assessment found that a UST had been removed, there was an AST with dispensers, and subsurface hydrocarbon contamination (both soil and groundwater) was identified. Based on that information, DHEC began working with the lessee to get the contamination addressed on this site, identified as Site ID# 01935. DHEC was not successful in getting the contamination addressed with the lessee and contacted the Authority as the owner of the property. On February 26, 2014, the Authority was notified by DHEC that based on the groundwater monitoring report received August 29, 2013, the submittal of a Tier II Assessment Plan was required under the South Carolina Pollution Control Act (SC Code Ann. § 48-1-50(6), § 48-1-50(20), and § 48-1-50(21). The Authority agreed to monitor the progress of the environmental work and assist with financing the cost of environmental assessment for the lessee. 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 results for the site, and the Authority entered into a Responsible Party Voluntary Cleanup Contract ("VCC") with DHEC on March 18, 2022. The VCC addresses the Authority and DHEC's cooperative plan for remediation of the creosote on the property. The Authority has submitted its Work Plan for the VCC process, which DHEC has accepted, and work has begun under that agreement, while the hydrocarbon component continues independent of the VCC.

No pollution remediation liabilities were recorded for the years ended December 31, 2022 and 2021.

Commitment to Sustainability - The Authority is committed to improving the lives of South Carolinians through sustainable business practices that prioritize long-term economic, environmental, and social performance combined with effective corporate governance. Corporate priorities and goals align with this commitment by focusing on areas such as employee safety, environmental stewardship, cost of power, system reliability, customer satisfaction, and employee and supplier diversity.

Environmental initiatives are numerous and include a comprehensive environmental management system focused on compliance and risk management; transitioning the generating fleet to lower carbon and carbon-free resources; responsibly closing ash and gypsum ponds while beneficially reusing coal combustion products in the drywall, concrete, cement, and agriculture industries; restoring hundreds of acres of wetlands at the Camp Hall commerce park and former Grainger Generating Station; collecting more than 30 million gallons of used oil throughout South Carolina through the Give Oil For Energy Recovery (GOFER) program; and native plantings and a pollinator pathway at the Jamison Solar Farm, the first and only Gold Certified Solar Habitat in the State. In addition, the EmpowerSC program is a comprehensive collection of energy efficiency and demand-side management programs designed to encourage residential and commercial customers' adoption of electric vehicles, home and community solar generation, energy efficient appliances and heating, ventilation, and air conditioning systems, and more.

The Authority's economic and social initiatives and recognitions include jobs creation through economic development grants, low interest loans, and experimental rates to industrial customers, and other organizations expanding or locating in South Carolina; partnering with State agencies and private companies to provide access to 1,200 miles of fiber and transmission poles for broadband internet expansion to unserved areas; hosting a Supplier Diversity Fair to help increase the number of minority, women, and veteran-owned businesses supplying products and services to the Authority; earning multiple Safety Awards of Excellence from the American Public Power Association; establishing the Inclusion, Diversity, Equity, and Awareness ("IDEA") Council to support corporate strategies that increase DE&I Awareness, reinforce and enhance a culture of equity and inclusion, and improve the Authority's diversity footprint. Also enhancing stakeholder engagement through the Integrated Resource Plan process, a stakeholder advisory committee established by the Board, and numerous community outreach efforts.

The Authority is also a long-time member of the Electric Power Research Institute's ("EPRI") Energy Sustainability Interest Group, which is designed to develop the tools and resources needed to establish and enhance sustainability at electric power companies.

Additional information about the Authority's sustainability ef [illegible] available on the Authority's website at the following address: [illegible] powersource-magazine-xkf4p3mxu3/full-view.html. The Authority's next sustainability report is expected to be available by the third-quarter of 2023.

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. In April 2022, the FERC requested additional information from the Authority regarding proposed removal of a land mass immediately downstream of the Santee Dams to facilitate safe hydraulic passage of the proposed higher minimum flows into the Santee River. The Authority provided the requested information to the FERC in June 2022. 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. The Authority has recorded approximately $550,000 in capital assets for the FERC Hydroelectric license through December 31, 2022.

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) (Act 90), which established reforms by amending the state laws applicable to the Authority.

Changes under Act 90 include new board qualifications and duties, a new rate process for the Authority. Joint Bond Review Committee approval of proposed debt issuance, certain oversight authority to the Office of Regulatory Staff, and new requirements for the SCPSC to approve the Authority's Integrated Resource Plan and new generation facilities. The Authority is complying with Act 90 and the Act's changes are being incorporated into the regular operations of the Authority.

Since the enactment of Act 90, the Joint Bond Review Committee has approved several Authority real estate and financing transactions, the South Carolina Public Service Commission (SCPSC) has opened dockets related to the Authority's renewable energy procurement and future resource plans, the Governor has appointed a new Authority Chair who has been confirmed by the SC Senate, and the Agency Head Salary Commission has approved the compensation package for the Authority's current CEO.

During the 2022 state legislative session, the South Carolina General Assembly adopted a budget that included a proviso authorizing the Office of Regulatory Staff to charge the Authority for its annual regulatory expenses associated with Act 90. The budget proviso provided for these annual amounts to be deducted from the Authority's annual payment to the State, thereby avoiding an additional expense to the Authority's customers. Through the year ended December 31, 2022, no amounts have been deducted from the Authority's payment to the State.

The 2023-2024 SC legislative session began January 10, 2023, and two items on the South Carolina General Assembly's agenda include: 1) an anticipated report from the Electricity Market Reform Measures study committee, a joint legislative committee consisting of 4 Senators and 4 House members, analyzing market options for South Carolina; and, 2) economic development related legislation to include energy provisions, being considered and developed by a special SC House Ad Hoc committee appointed by the Speaker of the SC House of Representatives.

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, the cases may be subject to trial by a jury, judge, or arbitrator(s), 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

Jessica S. Cook et al. v. the Authority, the Authority's Board of Directors (certain former and current Directors named), SCE&G, SCANA Corporation, SCANA Services, Inc., Palmetto Elec. Coop., & Central Elec. Pwr. Coop.

Plaintiffs filed this putative class action in the Hampton County Court of Common Pleas on August 22, 2017, in connection with the Authority's decision to suspend construction of Summer Nuclear Units 2 and 3. Numerous amended complaints, responsive pleadings, and cross-claims were filed, up to and including a Fifth Amended Complaint. Plaintiffs' claims generally sought on behalf of a class of members the repayment of amounts paid by ratepayers attributable to Summer Nuclear Units 2 and 3 under statutory, contract, tort, and equitable theories. Plaintiffs also asserted claims against Palmetto, Central, SCANA, SCE&G, and SCANA Services. As detailed below, the case was resolved at mediation and an Amended Order Approving Settlement was entered on July 31, 2020, which approved the terms of the settlement reached by the parties resolving this matter and *Timothy Glibowski et al. v. SCANA, SCE&G, the Authority, et al.*

In addition to resolving Cook, the Cook Settlement Agreement resolved this putative class action filed in the Beaufort Division of the United States District Court for the District of South Carolina on January 31, 2018. The Plaintiffs filed an amended complaint on April 23, 2018 adding the Authority as a defendant. As against the Authority, Plaintiffs' claims arose from decisions to suspend construction of Summer Nuclear Units 2 and 3. The action was brought on behalf of a putative class of persons comprised of SCANA customers, Authority customers, and Central customers who paid advance charges for costs associated with the construction of the units from 2007 to 2019.
Amended pleadings were filed, up to and including a Third Amended Complaint filed on July 30, 2019. The Third Amended Complaint asserted RICO and RICO Conspiracy claims against SCANA, SCE&G, SCANA's officers, the Authority and three now retired employees of the Authority as well as a takings claim against the Authority. Plaintiffs sought actual damages, treble damages under RICO, and attorneys' fees. As the claims in this matter were fully resolved as part of the Cook matter described above, the Court entered an order dismissing this matter on May 15, 2020.

The Cook Settlement Agreement generally provides for the dismissal and the release of all claims belonging to the class members against the Defendants, including those against the Authority. The class members are defined as all customers of the Authority that paid utility bills, during the time period from January 1, 2007 to January 31, 2020, with rates that were calculated in part to pay costs of Summer Nuclear Units 2 and 3 (the "Class Members"). In exchange for dismissal and release of the claims, SCE&G (n/k/a) DESC and the Authority agreed to make certain payments to a Common Benefit Fund (the "Fund") to be paid to Class Members. The Authority's portion of the payments to the Fund is $200 million, which were paid in three annual installments in the third quarters of 2020, 2021, and 2022, in the amount of $65 million, $65 million, and $70 million, respectively. In addition, the Authority agreed to a freeze on its rates consistent with rates projected in the Reform Plan beginning in 2020 through the end of 2024, subject to certain exceptions like costs arising from named storm events or changes in the law. The description here in this paragraph of the Cook Settlement Agreement is a general summary of the major provisions. A copy of the agreement can be found at http://www.santeecooperclassaction.com/Content/Documents/Settlement%20Agreement.pdf.

The Authority submits a compliance report to the Court annually through 2030.

<u>Annual Cook Compliance Reports</u>

2020 Annual Compliance Report. The Cook Settlement Agreement requires the Authority to file an annual report by April 30th of each year demonstrating compliance with certain terms of the Settlement Agreement and identifying Cook Rate Freeze Exceptions the Authority has determined are eligible for collection after the Cook Rate Freeze Period. On April 30, 2021, the Authority filed its first report (the "2020 Annual Compliance Report"), covering the period from August 1, 2020 through December 31, 2020 (the "2020 Reporting Period"). The 2020 Annual Compliance Report identified three categories of costs and expenses occurring during the 2020 Reporting Period, including (1) $5.2 million resulting from a change in law due to the COVID-19 pandemic; (2) $1.2 million resulting from named storm Hurricane Isaias; and (3) $13.3 million attributable to Central Load Deviations (collectively, the "2020 Cook Rate Freeze Exceptions").

As allowed by the Cook Settlement 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. On September 10, 2021, the Court of Common Pleas for the Thirteenth Judicial Circuit (the "Court") deferred any judicial action on Central's request.

2021 Annual Compliance Report. The Authority filed its 2021 Annual Compliance Report covering the period from January 1, 2021 through December 31, 2021 (the "2021 Reporting Period") on April 29, 2022, demonstrating the Authority's compliance with the Cook Settlement Agreement (the "2021 Annual Compliance Report" and, together with the 2020 Annual Compliance Report, the "2020 and 2021 Annual Compliance Reports"). The 2021 Annual Compliance Report identified eight situations falling within four categories of costs and expenses as Rate Freeze Exceptions. The four categories include (1) $11.9 million resulting from various changes in law; (2) $175 thousand resulting from named Tropical Storm Elsa; (3) $43.4 million resulting from the fire and subsequent mine closure due to a change in law ($37.8 million) and the fire and failure of equipment at VC Summer 1 ($5.6 million); and (4) $15.4 million attributable to Central Load Deviations (collectively, the "2021 Cook Rate Freeze Exceptions").

On May 12, 2022, counsel to class members sent a letter to the Authority regarding seven of the 2021 Cook Rate Freeze Exceptions and requested additional information. The Authority provided the requested information on June 15, 2022. On June 22, 2022, the Authority received a letter from Central, which included comments, questions, objections, and requested additional information. The Authority responded to Central's letter and provided the same information provided to class counsel.

On September 9, 2022, class counsel filed a motion challenging the 2021 Cook Rate Freeze Exceptions in the Authority's 2021 Annual Compliance Report. The Authority submitted an initial response on September 19, 2022, which included a joint proposal (with Central and class counsel) to discuss the exceptions. On September 26, 2022, the Court entered an order denying, at this time, class counsel's (1) motion to rule on the applicability of the 2021 Cook Rate Freeze Exceptions and (2) the request to appoint an independent auditor. Following the Court's order, the Authority updated the Court that discussions are ongoing.

Pending Litigation

(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 $76 million for fiscal years 2017, 2018, 2019, and January – July 2020 and a reduction in future contributions from Central in a yet undetermined amount. The Authority responded to Central, noting its disagreement with Central's position. The parties will proceed 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 was selected, and the arbitration is scheduled to occur in 2023. 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. 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 COE based on a calculation which is in dispute. 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 ASBCA denied the Authority's appeals and remanded to the parties to negotiate 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 [redacted]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 17.41 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 12.41 percent is contributed to the SCRS. As of December 31, 2022, the Authority had 98 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 17.41 percent of the total payroll for SCRS retirement. For 2022, 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, 2022, the Authority reported a liability of $308.5 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, 2022 and determined by an actuarial valuation as of July 1, 2021. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of $22.4 million paid to SCRS for the year ended June 30, 2022 relative to the actual contributions of $1.9 billion from all participating employers. The schedule of the Authority's proportionate share of the net pension liability for the years ended June 30, 2022 and 2021 are as follows:

	June 30, 2022	June 30, 2021
Authority's proportion of the net pension liability (%)	**1.21%**	1.28%
Authority's proportion of the net pension liability (millions)	**$ 295.2**	$ 278.9
Authority's covered employee payroll (millions)	**$ 148.9**	$ 152.7
Authority's proportion of the net pension liability as a percentage of its covered employee payroll	**198%**	183%
Plan fiduciary net position as a percentage of the total pension liability	**57.10%**	60.70%

For the year ended December 31, 2022, the Authority recognized a pension expense of $12.4 million, the Authority's proportionate share of the total pension expense. At December 31, 2022, 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	**$ 2,576**	**$ 1,309**
Changes of assumptions	**9,481**	**0**
Net difference between projected and actual earnings on pension plan investments	**43,528**	**43,071**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**771**	**16,455**
Authority's contributions subsequent to the measurement date	**11,346**	**0**
Total	**$ 67,702**	**$ 60,835**

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 pension liability in the year ending December 31, 2023. 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, 2022. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2022, was 3.767 years for SCRS.

Year Ending December 31:	
	(Thousands)
2023	**$ (1,630)**
2024	**(170)**
2025	**(10,395)**
2026	**7,717**
Total	**$ (4,478)**

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 was recognized as a reduction of the net pension liability in the year ended 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	$ (32,327)

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, 2022:

- **Measurement Date**	**June 30, 2022**
- **Valuation Date**	**July 1, 2021**
- **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, 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%

Discount Rate - The discount 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, 2022, 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 2022 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 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%**	**6.79%**	**3.12%**
Private Equity	**9.00%**	**8.75%**	**0.79%**
Real Assets			
Real Estate	**9.00%**	**4.12%**	**0.37%**
Infrastructure	**3.00%**	**5.88%**	**0.18%**
Diversified Credit			
Bonds	**26.00%**	**(0.35)%**	**0.09%**
Private Debt	**7.00%**	**6.00%**	**0.42%**
Total Expected Real Return	**100.0%**		**4.79%**
Inflation for Actuarial Purposes			**2.25%**
Total Expected Nominal Return			**7.04%**

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%

Sensitivity Analysis - For the measurement date as of June 30, 2022, 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 4.25% 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 (Thousands)**	**1.00% Increase**
Authority's proportionate share of the net pension liability	**$ 392,700**	**$ 308,585**	**$ 238,582**

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

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, 2022, the Authority reported an asset of $3.5 million and a liability of $13.3 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	**$ 14**	**$ 371**
Changes of assumptions	**5**	**0**
Net difference between projected and actual earnings on pension plan investments	**1,492**	**642**
Authority's contributions subsequent to the measurement date	**188**	**0**
Total	**$ 1,699**	**$ 1,013**

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, 2023. 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, 2022.

Year Ending December 31:	
	(Thousands)
2023	**$ (122)**
2024	**19**
2025	**227**
2026	**373**
2027	**0**
Total	**$ 497**

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)

Summer Nuclear Unit 1 Retirement - The Authority and DESC. 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, 2022, and 2021, the Authority had a pension liability of $6.7 million and $8.1 million, respectively.

In accordance with FASB ASC 715, the Authority has a regulatory asset balance of approximately $5.9 million and $9.2 million for the unfunded portion of pension benefits at December 31, 2022 and 2021, respectively. Additional information may be obtained by reference to DESC. Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2022.

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 greater than 5 years but less than 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, 2022, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	1,146
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	-
Active Plan Members	1,509
Total Plan Members	**2,655**

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

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 results in a lower OPEB liability and established a method for amortizing the regulatory asset as funding occurs.

Net OPEB Liability - The components of the net OPEB liability at June 30, 2022 were as follows:

	(Thousands)
Total OPEB Liability	$ 299,066
Plan fiduciary net position	95,249
Authority's net OPEB liability	$ 203,817
Plan fiduciary net position as a percentage of the total OPEB liability	31.85%

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%

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; 25 years remaining as of the beginning of FYE21
Asset Valuation	Market Value
Investment Rate of Return	3.00%, net of investment expenses, including inflation
Inflation	2.25%
Salary Increases	3.00% to 9.50%, including inflation
Demographic Assumptions	Based on the experience study covering the five year period ending June 30, 2019 as conducted for the South Carolina Retirement Systems (SCRS)
Mortality	For healthy retirees, the gender-distinct South Carolina Retirees 2020 Mortality Tables are used with fully generational mortality projections using 80% of Scale UMP to account for future mortality improvements and adjusted with multipliers based on plan experience.
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 5.30% declining to an ultimate rate of 3.7% 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	2.34%	0.6%
Fixed Income	97.66%	5.12%
Total Blended Average	**100.0%**	**5.19%**

Asset Allocation at June 30, 2022

The rate of return for 2022 on the Trust was (25.9)%.

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 3.69% (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, 2022

Measurement period ending June 30	**2022**	2021
	(Thousands)	
Service Cost	**$ 7,098**	$ 6,899
Interest on the total OPEB liability	**8,755**	9,573
Difference between expected and actual experience	**177**	7,692
Changes of Assumptions	**(260)**	3,975
Benefit payments	**(10,013)**	(9,813)
Net change in total OPEB liability	**5,757**	18,326
Total OPEB liability - beginning	**293,309**	274,983
Total OPEB liability - ending (a)	**$ 299,066**	$ 293,309
Plan fiduciary net position		
Employer contributions	**$ 20,283**	$ 18,573
OPEB plan net investment income	**(20,631)**	(1,686)
Benefit payments	**(10,013)**	(9,813)
OPEB plan administrative expense	**(171)**	(167)
Net change in plan fiduciary net position	**(10,532**	6,907
Plan fiduciary net position - beginning	**105,781**	98,874
Plan fiduciary net position - ending (b)	**$ 95,249**	$ 105,781
Net OPEB liability - ending (a) - (b)	**$ 203,817**	$ 187,528
Plan fiduciary net position as a percentage of total OPEB liability	**31.85%**	36.06%
Covered-employee payroll (dollars)	**$ 146,304,252**	$ 148,938,030
Net OPEB liability as a percentage of covered-employee payroll	**139.31 %**	125.91 %

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, 2022.

	1.00% Decrease	Current Discount Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 254,294	$ 203,817	$ 163,311

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, 2021.

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

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 assumed healthcare trend rates and for what the Authority's net OPEB liability would be if it were calculated using a trend rate that is 1.00% lower or 1.00% higher than the current trend rate as of June 30, 2022.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 152,719	$ 203,817	$ 270,319

The following presents the net OPEB liability of the Authority calculated using the assumed healthcare trend rates and for what the Authority's net OPEB liability would be if it were calculated using a trend rate that is 1.00% lower or 1.00% higher than the current trend 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

OPEB Expense and Deferred Outflows (Inflows) of Resources Related to OPEB - For the year ended December 31, 2022, the Authority recognized OPEB expense of $23.9 million. At December 31, 2022, 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	**$ 5,754**	**$ 5,564**
Changes of assumptions	**21,855**	**1,770**
Net difference between projected and actual earnings on OPEB plan investments	**20,817**	**0**
Authority's contributions subsequent to the measurement date	**9,113**	**0**
Total	**$ 57,539**	**$ 7,334**

The Authority reported $9.1 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, 2023. 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, 2022.

Year Ending December 31:		
		(Thousands)
2023	$	10,687
2024		11,166
2025		11,605
2026		6,123
2027		1,519
Thereafter,		(9)
Total	$	41,091

For the year ended December 21, 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

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, 2022 and 2021 were both approximately $12.8 million and $12.4 million, respectively.

In accordance with FASB ASC 715, the Authority recorded a regulatory asset of approximately $55,000 and $600,000 for the unfunded portion of OPEB costs at December 31, 2022 and 2021, respectively. Additional information may be obtained by reference to the DESC. Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2022.

Note 13 – Credit Risk and Major Customers

In 2022 and 2021, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:		2022		2021
		(Millions)		
Central	**$**	**1,059**	$	1,003

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, 2022 and 2021 was $2.5 million and $2.6 million, respectively.

Note 14 – Storm Damage

2022

In September 2022, the Authority's system sustained damages from Hurricane Ian. As a result, portions of South Carolina were declared federal disaster areas for damages, and the entire state was declared eligible for protective measures expense relief. During 2022, the Authority incurred $3.2 million in capital and maintenance costs. A receivable of $2.4 million was recorded as of December 31, 2022, in anticipation of federal reimbursement in 2023.

Note 15 – Impact of Novel Coronavirus (COVID-19) Pandemic

The Authority will continue to monitor 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 2023.

The Authority captured all costs associated with the Protective Measures incurred in 2022, 2021 and 2020. The amounts were approximately $1.0 million, $3.5 million, and $13.7 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. Through December 31, 2022, the Authority has been reimbursed $70,992 from FEMA for prior Covid-19 costs and has recognized a regulatory asset of $8.7 million for unreimbursed COVID-19 costs (see Note 5- *Cook Settlement as to Rates*).

Note 16 – Subsequent Events

FERC Licensing

The Authority has been operating the Santee Cooper Hydroelectric Project under a standing annual license renewal that was effective from the March 31, 2006 date of expiration of the previous license until the new license was issued. This annual renewal continued through December 31, 2022. On January 20, 2023, FERC issued a new 50-year license to the Authority, effective January 1, 2023 through January 1, 2073. Anticipated implementation costs for additional environmental requirements and threatened, endangered, candidate and proposed species protection measures under the new license are estimated to be between $84 million and $179 million over the 50-year term.

Winyah Generating Station

In March 2021, as part of the Authority's goal of reducing its reliance on coal-fired generation and to take advantage of the retirement exemption in the NPDES Steam Electric Effluent Limitation Guidelines ("ELG"), the Board approved the retirement of all of the units of the Winyah Generating Station and authorized management to take steps necessary to affect the eventual retirement.

As part of the phased retirement of the Winyah Generating Station, Winyah Unit 4 was idled in April 2021 as a result of the Authority having excess capacity on its system. The other units at the Winyah Generating Station, specifically Unit 1, Unit 2 and Unit 3, have remained active in the capacity reserves and on economic dispatch. Winyah Unit 4 was brought back online in December 2021, ahead of the winter season to provide additional grid resiliency during peak load periods on an as-needed basis. At that time, the unit's capacity was not counted in the planning reserves and it was not economically dispatched. However, the Authority's 2022 updated 20-year demand and energy projections reflected greater load growth than previous projections. Additionally, in connection with the development of the Authority's triennial integrated resource plan (the "2023 IRP"), the Authority is studying the appropriate levels of planning reserves margins for the System. The planning reserve margin study prepared by an outside consultant hired in connection with the development of the 2023 IRP, indicated a need for increased planning reserve margins by 2026. The combination of projected increase in load growth of the System and increased planning reserve margins has resulted in a near term capacity need. In response to this capacity need, the Authority has made the decision to return Winyah Unit 4 to its capacity planning reserves to ensure that the Authority has sufficient capacity during peak load periods. The return of Winyah Unit 4 is not immediately expected to increase the Authority's overall energy output from coal units due to coal supply issues. The Authority will continue to monitor the situation and efforts to conserve coal consumption.

On February 9, 2023, the Authority and Central Electric Power Cooperative, Inc., executed a memorandum of understanding which memorializes, among other things, Central's willingness to pay for their share of a treatment system for FGD wastewater in order to keep Winyah online beyond the retirement date in the event replacement power cannot be brought online by that time. The Authority expects that the system will be similar to the one being designed for Cross, which we expect to cost about $153.0 million and be operational in December 2025. Based on this, budget estimates for Winyah are expected to cost about $150.0 million. On February 21, 2023, the Authority submitted a letter to SCDHEC's Bureau of Water requesting this compliance option be added – along with retirement and the voluntary incentive program options – to the draft permit, which we have requested as soon as possible.

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Required Supplemental Financial Data:

Schedule of Proportionate Share of the Net Pension Liability
Required Supplementary Information

Years Ended in June 30,	**2022**	2021	2020	2019	2018	2017	2016	2015	2014[1]
Authority's proportion of the net pension liability (%)	**1.21%**	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)	**$295.2**	$278.9	$327.9	$309.7	$321.8	$323.1	$309.7	$273.6	$249.7
Authority's covered payroll (millions)	**$148.9**	$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	**198%**	183%	219%	205%	206%	210%	210%	194%	184%
Plan fiduciary net position as a percentage of the total pension liability	**57.1%**	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.

Schedule of Pension Plan Contributions
Required Supplementary Information
(Millions)

Years Ended December 31,	**2022**	2021	2020	2019	2018	2017	2016	2015	2014[1]
Required Contributions:									
From the Authority	**$ 23.2**	$ 22.1	$ 22.1	$ 20.6	$ 19.8	$ 17.7	$ 15.6	$ 14.8	$ 13.9
From employees	**12.3**	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	**$ 23.2**	$ 22.1	$ 22.1	$ 20.6	$ 19.8	$ 17.7	$ 15.6	$ 14.8	$ 13.9
From employees	**12.3**	12.5	12.9	12.4	12.8	12.6	11.8	11	10.2
Contribution deficiency (excess)	**$ -**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Authority's covered payroll	**137.2**	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	**17.00%**	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
Required Supplementary Information
(Thousands)

Measurement period ending June 30,	2022	2021	2020	2019	2018[1]
Service Cost	$ 7,098	$ 6,899	$ 6,821	$ 4,641	$ 5,405
Interest on the total OPEB liability	8,755	9,573	9,425	10,375	10,073
Difference between expected and actual experience	177	7,692	242	(12,859)	(291)
Changes of Assumptions	(260)	3,975	(2,717)	44,641	0
Benefit payments	(10,013)	(9,813)	(9,351)	(8,937)	(7,253)
Net change in total OPEB liability	5,757	18,326	4,420	37,861	7,934
Total OPEB liability - beginning	293,309	274,983	270,563	232,702	224,768
Total OPEB liability - ending (a)	$ 299,066	$ 293,309	$ 274,983	$ 270,563	$ 232,702
Plan fiduciary net position					
Employer contributions	$ 20,283	$ 18,573	$ 18,812	$ 27,483	$ 14,455
OPEB plan net investment income	(20,631)	(1,686)	5,717	5,501	(120)
Benefit payments	(10,013)	(9,813)	(9,351)	(8,937)	(7,253)
OPEB plan administrative expense	(171)	(167)	(153)	(126)	(104)
Net change in plan fiduciary net position	(10,532)	6,907	15,025	23,920	6,978
Plan fiduciary net position - beginning	105,781	98,874	83,849	59,928	52,950
Plan fiduciary net position - ending (b)	$ 95,249	$ 105,781	$ 98,874	$ 83,848	$ 59,928
Net OPEB liability - ending (a) - (b)	$ 203,817	$ 187,528	$ 176,109	$ 186,714	$ 172,774
Plan fiduciary net position as a percentage of total OPEB liability	31.85%	36.06%	35.96%	30.99%	25.75%
Covered-employee payroll	$146,304,252	$148,938,030	$149,128,347	$149,862,640	156,058,022
Net OPEB liability as a percentage of covered-employee payroll	139.31%	125.91%	118.09%	124.59%	110.71%

(1) Information is not available for years prior to 2018.

Schedule of OPEB Contributions
Required Supplementary Information
(Thousands)

For December	Actuarially Determined Contribution	Actual Contribution	Contribution Deficiency (Excess)	Covered Payroll	Actual as a % of Covered Payroll
2022	**$ 17,867**	**$ 18,133**	**$ (262)**	**$ 145,554**	**12.46%**
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
2022	**3.00%**
2021	3.00%
2020	3.50%
2019	3.50%
2018	4.50%

Schedule of Investment Returns
Required Supplementary Information

	2022	**2021**	2020	2019	2018[1]
Annual money-weighted rate of return, net of investment expenses	**(25.89)%**	**(1.63)%**	6.46%	7.96%	(0.21)%

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

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

Jimmy D. Staton	President and Chief Executive Officer
Rahul Dembla	Chief Planning Officer
Kenneth W. Lott III	Chief Financial and Administration Officer
J. Michael Poston	Chief Customer Officer
Monique L. Washington	Chief Audit and Risk Officer
J. Martine “Marty” Watson	Chief Power Supply Officer
Pamela J. Williams	Chief Public Affairs Officer and General Counsel

Other Officers

Traci J. Grant	Director of Corporate Services and Corporate Secretary
Dominick G. Maddalone	Senior Director of Innovation and Chief Information Officer
Daniel T. Manes	Controller
Suzanne H. Ritter	Treasurer and Director of Financial Planning

Notes:

The Board of Directors hired Jimmy D. Staton as President and CEO, effective March 1, 2022. Previous President and CEO Mark B. Bonsall returned to retirement and his last day at Santee Cooper was Jan. 7, 2022, and 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.

Traci J. Grant, Director of Corporate Services, assumed the role of Corporate Secretary, effective March 28, 2022, after B. Shawan Gillians’ departure from Santee Cooper.

The Board of Directors named Rahul Dembla as Chief Planning Officer, effective July 1, 2022.

J. Michael Poston retired on Dec. 31, 2022. The Board of Directors named Victoria N. Budreau as Chief Customer Officer, effective Jan. 1, 2023.

Office Locations

MONCKS CORNER OFFICE

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