Nebraska Public Power District

Always there when you need us

2022 Financial Report

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Vision

We are a premier energy provider bringing the best of public power to Nebraskans, powering everyday life and a brighter future.

Mission

Safely generate and deliver reliable, low-cost, sustainable energy and related services, while providing outstanding customer service.

CORPORATE PROFILE

Nebraska Public Power District (NPPD), a public corporation and political subdivision of the State of Nebraska, operates an integrated electric utility system including generation, transmission and distribution facilities.

NPPD owns or has operating control of 30 generating facilities. This diverse power resource mix produces energy from a variety of fuel sources including coal, nuclear, natural gas, oil, hydro, wind and solar. NPPD operates 5,376 miles of transmission and subtransmission lines and 2,825 miles of distribution lines.

Revenues are primarily derived from wholesale power supply agreements with 38 municipalities and 23 public power districts and/or cooperatives. NPPD also serves an average of nearly 93,000 residential, commercial and industrial customers in 79 Nebraska communities at retail.

Formed by a merger on Jan. 1, 1970, NPPD works in partnership with other utilities, businesses and community leaders to help serve more than 530,000 Nebraskans with retail or wholesale electric power and energy-related services.

Control of NPPD and its operations is vested in an 11-member Board of Directors, popularly elected from within NPPD's chartered territory, including all or parts of 84 of Nebraska's 93 counties.

BY THE NUMBERS

30
GENERATING FACILITIES

5,376 MILES
TRANSMISSION & SUBTRANSMISSION LINES

2,825 MILES
DISTRIBUTION LINES

COMMUNITY POWERED BY NPPD

38
MUNICIPALITIES SERVED AT WHOLESALE

79
COMMUNITIES SERVED BY RETAIL

23
PUBLIC POWER DISTRICTS SERVED AT WHOLESALE

1,900+
TEAMMATES WORKING FOR YOU

$1.2 Billion
OPERATING REVENUE

530,000
NEBRASKANS SERVED IN PARTNERSHIP WITH OTHER UTILITIES

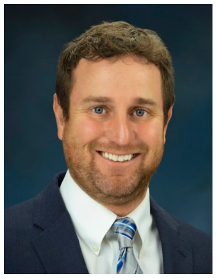
3,265 MW
DIVERSE GENERATION

93,000
RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS

84 of 93
NEBRASKA COUNTIES ARE SERVED BY NPPD

BOARD OF DIRECTORS

Mary A. Harding
Plattsmouth
Subdivision 1



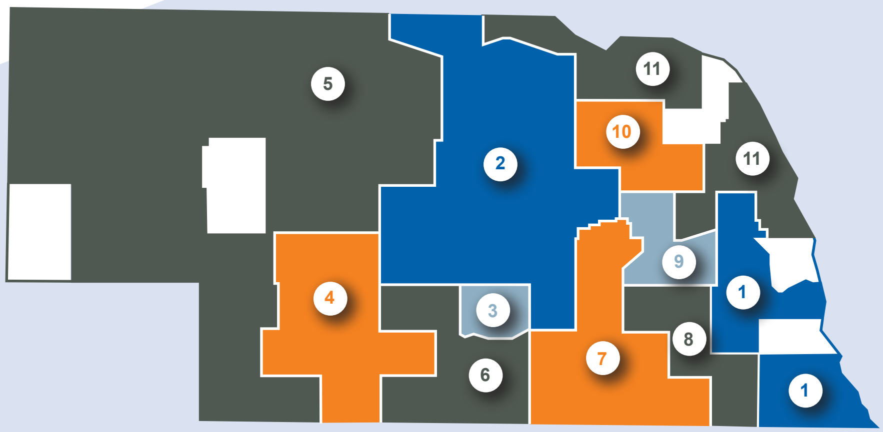
Aaron D. Troester
O'Neill
Subdivision 2

Melissa S. Freelend
Kearney
Subdivision 3

Bill C. Hoyt
McCook
Subdivision 4

Charlie C. Kennedy
Scottsbluff
Subdivision 5

Edward J. Schrock
Holdrege/Elm Creek
Subdivision 6



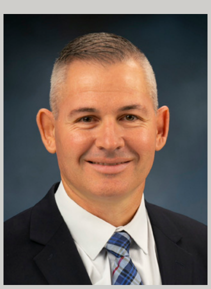
Wayne E. Williams
Central City
Subdivision 7

Gary G. Thompson
Clatonia
Subdivision 8

Jerry L. Chlopek
Columbus
Subdivision 9

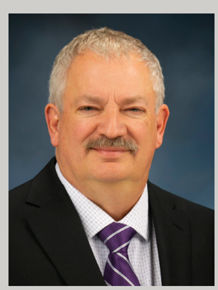
William D. Johnson
Pilger
Subdivision 10

Fred L. Christensen
Lyons
Subdivision 11



Derek S. Rusher
2023 Board Member
(Elected in November 2022)
Subdivision 3

David D. Gale
2023 Board Member
(Elected in November 2022)
Subdivision 4



Ronald J. Mogul Jr.
2023 Board Member
(Elected in November 2022)
Subdivision 8

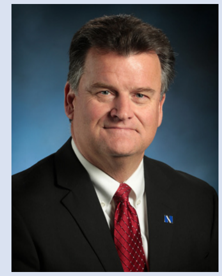
Sue D. Fuchtman
2023 Board Member
(Elected in November 2022)
Subdivision 10

SENIOR MANAGEMENT TEAM

Thomas J. Kent
President & Chief Executive Officer

Timothy J. Arlt
Vice President, Corporate Strategy & Innovation

Dallas M. Beshaler
Vice President, Human Resources & Corporate Services



Kendall B. Curry (1)
Vice President, Customer Services & Chief Customer Officer

John A. Dent Jr.
Executive Vice President, Chief Nuclear Officer

Courtney A. Dentlinger (1)
Vice President, Customer Service & External Affairs & Chief Customer Officer

Khalil M. Dia
Cooper Nuclear Station Site Vice President

Laura L. Kapustka
Executive Vice President, Chief Financial Officer & Treasurer

John C. McClure
Executive Vice President, External Affairs & General Counsel

Michael J. Spencer
Vice President, Energy Production

Robyn A. Tweedy
Vice President, Enterprise Technology & Chief Information Officer

Arthur R. Wiese
Vice President, Energy Delivery

(1) Mr. Curry served as Vice President, Customer Services & Chief Customer Officer until his replacement by Courtney Dentlinger on Sept. 1, 2022.

Jerry L. Chlopek
2022 Board Chair

Thomas J. Kent
President & CEO

A Message

FROM OUR 2022 BOARD CHAIR and CHIEF EXECUTIVE OFFICER

We often hear, "the only constant in life is change." This certainly rings true today, as many of us continue to deal with lingering impacts from the pandemic, including supply chain challenges impacting seemingly every industry, and continued inflationary pressures. We are not immune to these challenges, yet our team has risen to the occasion to maintain reliability and affordability.

We worked closely with our customers and fellow public power partners to navigate supply chain issues together, ensuring we will have a reliable stock of equipment. Our teammates learned to machine parts, alleviating the lengthy delays projected by third party fabricators for some critical components. While there are limitations to what our teams can do, their ingenuity is relieving some of our reliance on third parties. This is just one of many shining examples of our teammates overcoming challenges in impressive fashion.

Among the challenges our team members faced was another year of severe weather which impacted several of our retail and wholesale communities. At times it seemed like the severe weather wasn't going to end, and it led to a stressful storm season for many of our line crews who worked diligently to keep the lights on. While many of our communities were impacted, one situation that illustrates some of the challenges our crews faced came after a particularly strong pair of storms impacted the communities in and around York. A storm passed through the area and damaged approximately 20 structures on a transmission line south of York. Crews worked hard over the next several days to replace the damaged structures and less than a week after the first storm rolled through, a second storm took out 40 structures on the same line. Storms in Nebraska can pack a punch, and NPPD has excellent crews who work safely and tirelessly to ensure our customers receive reliable service.

The other half of reliable service comes from the dedicated team members at our diverse mix of generation facilities located across Nebraska. Our generation teams performed well this past year and continued to provide customers with the affordable, reliable power we all depend upon. Gerald Gentleman Station's Unit 2 celebrated its 40th anniversary of producing low-cost, reliable generation, and the efforts of that team will ensure it can continue to do so for years to come. Our team members at Cooper Nuclear Station successfully completed their 33rd refueling outage. Refueling outages take a considerable amount of careful planning and execution, and thanks to the efforts of that team, Cooper continues to be a great source of reliable, carbon-free generation for our customers.

Among other items to celebrate this past year were the opening of two new community solar facilities in Norfolk and York. This brings the total number of community solar facilities in NPPD retail communities up to six, with a seventh facility expected to go on-line in Ogallala in early 2023. The newest locations currently in operation, include the 3.2-megawatt facility located just northwest of York, and the state's largest solar facility currently in operation at 8.5 megawatts, located near Norfolk, which also includes 1 megawatt of battery storage. These community solar projects continue to be a great way for NPPD to partner with retail communities who want to pursue local renewable energy generation to help power their homes and businesses.

While change has been common in many areas of our lives, one thing has continued to remain steady for our customers -- our rates.

In 2022, NPPD retail customers experienced their ninth consecutive year of stable rates, and wholesale customers experienced a fifth straight year with no rate increase. In addition, the NPPD board voted to return $74.2 million in rate stabilization funds back to wholesale customers, 38 municipalities and 23 rural public power districts and rural cooperatives, through a Production Cost Adjustment credit that ran from February 2022 to January 2023. This is something our team is extremely proud of and reflects the performance focus of our dedicated team members who live and work in the communities we serve. These successes are also reflected in NPPD's efforts to benchmark our wholesale rates against other utilities. NPPD does this by comparing our wholesale rates to the wholesale rates paid by 800 electric providers across the nation through the National Rural Utilities Cooperative Finance Corporation's annual assessment. In 2020, NPPD's rates ranked in the lowest quartile finishing at the 23.2 percentile compared to other utilities. That rank improved even further to the 12.4 percentile in 2021, and our team is set for another strong placement in the assessment following 2022's performance.

NPPD strives to be a premier energy provider, bringing the best of public power to Nebraskans, and through the resiliency of our teammates and customers, we continue our mission to safely generate and deliver reliable, low-cost, sustainable energy and provide outstanding customer service.

2022
FINANCIAL REPORT
NEBRASKA PUBLIC POWER DISTRICT

YEAR AT A GLANCE

KILOWATT - HOUR SALES		18.9	BILLION
OPERATING REVENUES	$	1,197.0	MILLION
COST OF POWER PURCHASED AND GENERATED	$	692.7	MILLION
OTHER OPERATING EXPENSES	$	387.2	MILLION
INVESTMENT AND OTHER INCOME (LOSS)	$	(10.2)	MILLION
DEBT AND RELATED EXPENSES	$	25.9	MILLION
INCREASE IN NET POSITION	$	81.0	MILLION
DEBT SERVICE COVERAGE		2.31	TIMES

2022 STATISTICAL REVIEW (Unaudited)

THE CUSTOMERS – Classifications

OPERATING REVENUES	Average Cents Per kWh Sold Less Government Taxes/Transfers[1]	Average Cents Per kWh Sold	Average Number of Customers	MWh Amount	MWh %	Revenues (in 000's) Amount	Revenues (in 000's) %
Retail:							
Residential	10.25 ¢	12.26 ¢	73,826	899,205	4.7	$ 110,209	9.2
Commercial	8.17 ¢	9.61 ¢	19,599	1,132,259	6.0	108,755	9.1
Industrial	4.05 ¢	4.45 ¢	60	2,059,935	10.9	91,698	7.7
Total Retail Sales	6.55 ¢	7.59 ¢	93,485	4,091,399	21.6	310,662	26.0
Wholesale:							
Municipalities[2]		5.67 ¢	38	1,366,501	7.2	77,414	6.5
Public Power Districts and Cooperatives[2]		5.14 ¢	23	8,396,381	44.3	431,692	36.0
Total Firm Wholesale Sales		5.21 ¢	61	9,762,882	51.5	509,106	42.5
Total Firm Retail and Wholesale Sales		5.92 ¢	93,546	13,854,281	73.1	819,768	68.5
Participation and Capacity Sales		4.62 ¢	5	1,861,914	9.8	86,006	7.2
Other Sales[3]		6.11 ¢	1	3,230,855	17.1	197,395	16.5
Total Electric Energy Sales		5.82 ¢	93,552	18,947,050	100.0	1,103,169	92.2
Other Operating Revenues[4]						72,465	6.0
Unearned Revenues[5]						21,338	1.8
Total Operating Revenues						$ 1,196,972	100.0

COST OF POWER PURCHASED AND GENERATED	MWh Amount	MWh %	Costs (in 000's) Amount	Costs (in 000's) %
Production[6]	14,649,116	74.2	$ 475,779	68.7
Power Purchased	5,093,633	25.8	216,946	31.3
Total Production and Power Purchased	19,742,749	100.0	$ 692,725	100.0

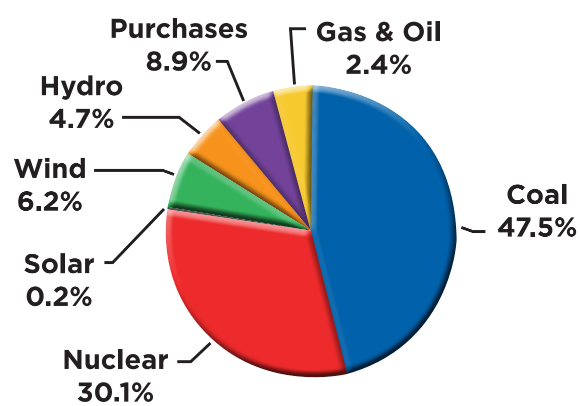
CONTRACTUAL AND TAX PAYMENTS (in 000's)[1]	Amount
Payments to Retail Communities	$ 32,594
Payments in Lieu of Taxes	10,217
Total Contractual and Tax Payments	$ 42,811

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,376
Number of Full-Time Employees	1,937

(1) Customer collections for taxes/transfers to other governments are excluded from base rates.
(2) Sales are total requirements, subject to certain exceptions.
(3) Includes sales in Southwest Power Pool ("SPP") and nonfirm sales to other utilities.
(4) Includes revenues for transmission and other miscellaneous revenues.
(5) Unearned revenues represent the net of revenue adjustments in the rate stabilization and other regulatory accounts, consistent with revenue requirements. Detailed information on unearned revenues is available in the Management's Discussion and Analysis.
(6) Includes fuel, operation and maintenance costs. Debt service and capital-related costs are excluded.

SOURCES OF THE DISTRICT'S ENERGY SUPPLY (% OF MWH)

This chart shows the sources of energy for sales, excluding participation sales to other utilities. Purchases were included in the appropriate source, except for those purchases for which the source was not known.



MANAGEMENT’S DISCUSSION AND ANALYSIS (Unaudited)

The Financial Report for the Nebraska Public Power District (the “District”) includes Management’s Discussion and Analysis (“MD&A”), Financial Statements, Notes to Financial Statements and Required Supplementary Information. The Financial Statements consist of the Statements of Net Position, the Statements of Revenues, Expenses, and Changes in Net Position, the Statements of Cash Flows, the Statements of Fiduciary Net Position, and the Statements of Changes in Fiduciary Net Position.

The following MD&A provides unaudited information and analyses of activities and events related to the District’s financial position or results of operations. The MD&A should be read in conjunction with the audited Financial Statements, Notes to Financial Statements and Required Supplementary Information.

The Statements of Net Position present assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position as of December 31, 2022 and 2021. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2022 and 2021. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2022 and 2021. The Statements of Fiduciary Net Position present the financial resources available for other postemployment benefits as of December 31, 2022 and 2021. The Statements of Changes in Fiduciary Net Position present the additions, deductions and changes in net position restricted for other postemployment benefits as of December 31, 2022 and 2021. The Notes to Financial Statements are an integral part of the basic Financial Statements and contain information for a more complete understanding of the financial position as of December 31, 2022 and 2021, and the results of operations for the years 2022 and 2021. The Required Supplementary Information include unaudited information required to accompany the Financial Statements.

OVERVIEW OF BUSINESS

The District is a public corporation and political subdivision of the State of Nebraska (the “State”). Control of the District and its operations is vested in a Board of Directors (“Board”) consisting of 11 members popularly elected from districts comprising subdivisions of the District’s chartered territory. The right to vote for the Board is generally limited to retail and wholesale customers receiving more than 50% of their annual energy from the District.

On February 18, 2022, the Nebraska Power Review Board approved an amendment to the District’s chartered territory to better align with the retail and wholesale service areas and voting subdivision boundaries based on the 2020 Census. With the amendment, the District’s chartered territory includes all or parts of 84 of the State’s 93 counties. Prior to the amendment, the District’s chartered territory included all or parts of 86 of the State’s 93 counties. The reduction in counties primarily resulted from the removal of the wholesale customers who did not sign the District’s 2016 wholesale power contracts (the “2016 Contracts”) which replaced the 2002 wholesale power contracts (the “2002 Contracts”). Those customers who remained on the 2002 Contracts phased out their power supply from the District at the end of 2021.

The District operates an integrated electric utility system including facilities for generation, transmission and distribution of electric power and energy for sales at wholesale and retail. Management and operation of the District is accomplished with a staff of 1,937 full-time employees as of December 31, 2022. The District has the power, among other things, to acquire, construct and operate generating plants, transmission lines, substations, and distribution systems and to purchase, generate, distribute, transmit and sell electric energy for all purposes. There are no investor-owned utilities providing retail electric service in Nebraska.

The District has no power of taxation, and no governmental authority has the power to levy or collect taxes to pay, in whole or in part, any indebtedness or obligation of or incurred by the District or upon which the District may be liable. The District has the right of eminent domain. The property of the District, in the opinion of its General Counsel, is exempt under the State Constitution from taxation by the State and its subdivisions, but the District is required by the State to make payments in lieu of taxes which are distributed to the State and various governmental subdivisions.

The District has the power and is required to fix, establish, and collect adequate rates and other charges for electrical energy and any and all commodities or services sold or furnished by it. Such rates and charges must be fair, reasonable, and nondiscriminatory and adjusted in a fair and equitable manner to confer upon and distribute among the users and consumers of such commodities and services the benefits of a successful and profitable operation and conduct of the business of the District.

THE SYSTEM

To meet the peak load in 2022 of 2,946.0 megawatts ("MW"), the District had available 3,647.9 MW of capacity resources that included 3,040.9 MW of generation capacity from 11 owned and operated generating plants and 19 plants over which the District has operating control, 443.5 MW of firm capacity purchases from the Western Area Power Administration ("Western"), and 163.5 MW of a capacity purchase from Omaha Public Power District's ("OPPD") Nebraska City Station Unit No. 2 ("NC2") coal-fired plant. Of the total capacity resources of 3,647.9 MW, 383.2 MW are being sold via participation sales or other capacity sales agreements, leaving 3,264.7 MW to serve the District's firm retail and wholesale customers and to meet capacity reserve requirements. The highest summer peak load of 3,030.3 MW was established in July 2012 and the highest winter peak load of 2,317.5 MW occurred in December 2022 for firm requirements customers.

The following table shows the District's capacity resources from generation and respective summer 2022 accredited capacity.

	CAPACITY RESOURCES		
Type	Number of Plants[1]	Summer 2022 Accredited Capacity (MW)[2]	Percent of Total
Steam - Conventional[3]	3	1,681.3	55.3
Steam - Nuclear	1	770.0	25.3
Hydro	5	113.7	3.7
Diesel[4]	9	69.3	2.3
Combustion Turbine[5]	3	123.6	4.1
Combined Cycle	1	219.5	7.2
Wind[6]	8	63.5	2.1
	30	3,040.9	100.0

(1) Includes three hydro plants and nine diesel plants under contract to the District.
(2) Accreditation by SPP for the summer season 2022, pursuant to standard performance tests conducted by the District. Pursuant to agreements with other utilities, a portion of the accredited capacity of certain generating plants has been sold to such utilities.
(3) Includes Gerald Gentleman Station, Sheldon Station and Canaday Station.
(4) The contract with Emerson ended December 31, 2021, which had a Summer 2021 accredited capacity of 1.4 MW, resulting in the decrease of one diesel plant from 2021 to 2022.
(5) Includes the Hallam, Hebron and McCook peaking turbines.
(6) Includes Ainsworth Wind Energy Facility and seven wind facilities under contract to the District

In 2021, the Board approved a goal to achieve net zero carbon emissions from generation resources by 2050. The District worked with its wholesale customers and the communities it serves to develop a policy to enable this goal, while maintaining affordability, reliability and system resiliency.

The District continues to collaborate with communities for solar projects, including projects in Norfolk and York which were both completed and commercialized in 2022. The Norfolk project is the District's first utility scale battery energy storage system rated for 1 MW of battery storage. Other solar projects underway and scheduled for completion are Ogallala in 2023 and Plattsmouth in 2024.

The following table shows the percentages of the District's energy supply produced from various sources and purchased, excluding energy produced with respect to Participation and Capacity Sales and Other Sales, in each of the five years 2018 through 2022.

SOURCES OF THE DISTRICT'S ENERGY SUPPLY
(% of MWh)

Year	Coal(1)	Nuclear	Hydro(2)	Wind(3)	Gas and Oil	Purchases(4)	Solar(5)
2018	52.6	28.5	5.9	6.0	2.3	4.6	0.1
2019	46.6	34.2	5.2	5.4	3.3	5.2	0.1
2020	42.1	33.2	5.9	6.2	3.9	8.6	0.1
2021	43.2	36.0	5.3	5.4	2.8	7.2	0.1
2022	47.5	30.1	4.7	6.2	2.4	8.9	0.2

(1) Includes NC2.
(2) Includes hydro purchases from Loup River Public Power District ("Loup"), over which the District has operating control, and Western.
(3) Includes Ainsworth Wind Energy Facility, Elkhorn Ridge Wind Facility, which began commercial operation in March 2009, Laredo Ridge Wind Facility, which began commercial operation in February 2011, Springview II Wind Energy Facility, which began commercial operation in August 2011, Crofton Bluffs Wind Facility, which began commercial operation in November 2012, Broken Bow I Wind Facility, which began commercial operation in December 2012, Steele Flats Wind Facility, which began commercial operation in November 2013 and Broken Bow II Wind Facility, which began commercial operation in October 2014.
(4) These are primarily purchases from SPP and JEA through 2019. In 2020, these are primarily purchases from SPP, as the JEA contract terminated on December 31, 2019. The increase in 2020 over 2019 was due primarily to additional energy purchases from the SPP Integrated Market as a result of a forced outage in August 2020 at Gerald Gentleman Station.
(5) Includes solar power purchases from solar retail Qualifying Local Generation.

The following table shows the generation facilities owned by the District and their respective fuel types, summer 2022 accredited capacity and in-service dates.

DISTRICT-OWNED GENERATION FACILITIES

Facility	Fuel Type	Summer 2022 Accredited Capacity (MW) (1)	In-Service Date
Gerald Gentleman Station Units No. 1 and No. 2	Coal	1,365.0	1979, 1982
Cooper Nuclear Station	Nuclear	770.0	1974
Beatrice Power Station	Combined Cycle	219.5	2005
Sheldon Station Units No. 1 and No. 2	Coal	217.0	1961, 1968
Combustion Turbines (3 generating plants)	Oil or Natural Gas	123.6	1973
Canaday Station	Natural Gas	99.3	1958
Hydro (2 generating plants)	Water	24.0	1887, 1939
Ainsworth Wind Energy Facility(2)	Wind	4.1	2005
		2,822.5	

(1) 2022 summer accredited net capacity based on SPP criteria.
(2) Nominally rated at 60 MW.

THE CUSTOMERS

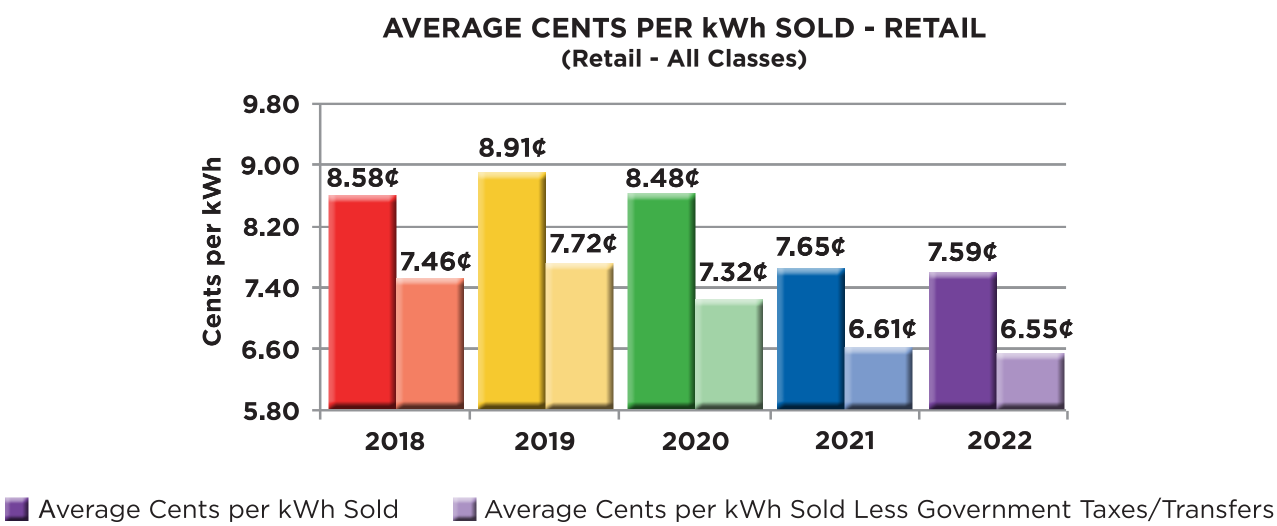
Retail and Wholesale Customers

In 2022, the District served an average of 93,485 retail customers. The District's retail service territory includes 77 municipal-owned distribution systems operated by the District within the state of Nebraska for the municipality pursuant to a Professional Retail Operations Agreement ("PRO Agreement") and two retail communities in South Dakota. Details of the District's PRO Agreements are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts,* in the Notes to Financial Statements.

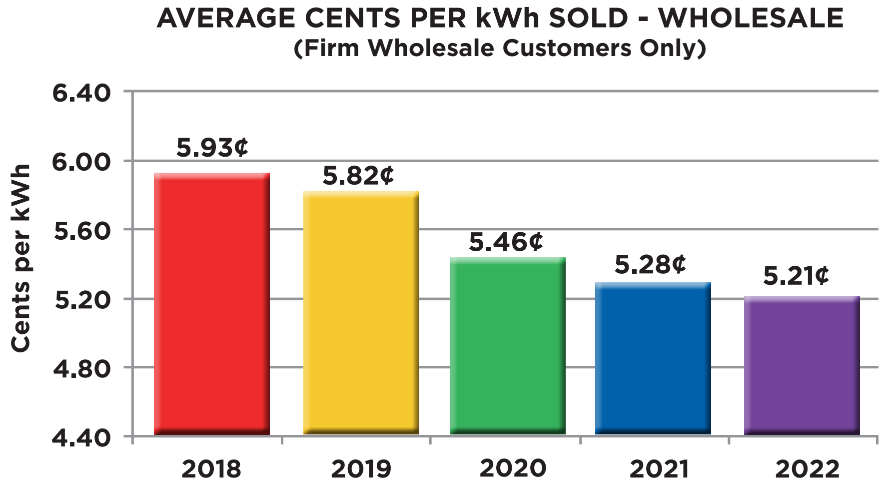
Effective January 1, 2016, the District entered into 20-year wholesale power sales contracts with a substantial number of its existing wholesale customers (the "2016 Contracts"). The 2016 Contracts replaced wholesale contracts that were entered into in 2002 (the "2002 Contracts"). The 2016 Contracts with these wholesale customers provide for the District to sell and such wholesale customers to purchase their total demand and energy requirements, subject to certain exceptions, from the District, in each year for a term of 20 years. The 2016 Contracts include provisions discussed below relating to a wholesale customer's right to reduce its purchases from the District. The 2016 Contracts are to continue in force after such 20-year term from year to year unless terminated on an anniversary thereof by at least five years' written notice given by either party, which notice may be given at any time on and after the fifteenth year of the term of the 2016 Contracts. Wholesale customers being served under the 2016 Contracts include 22 public power districts, one cooperative and 38 municipalities. Nineteen of the public power districts and the one cooperative are served under one contract with the Nebraska Generation and Transmission Cooperative. Wholesale customers served under the 2002 Contracts included one public power district and nine municipalities. The 2002 Contracts expired on December 31, 2021.

The 2016 Contracts allow a wholesale customer to reduce its demand and energy purchases from the District if the District's average annual wholesale power costs percentile level for a given year is higher than the 45th percentile level (the "Performance Standard Percentile") of the power costs of U.S. utilities for such year as listed in the National Rural Utilities Cooperative Finance Corporation Key Ratio Trend Analysis (Ratio 88) ("the CFC Data"). The goal, with respect to the cost of wholesale service (production and transmission), is that such costs are among the lowest quartile (25th percentile or less) for cost per kilowatt-hour ("kWh") purchased, as published by the CFC Data. The District's wholesale power costs percentiles were 12.4% and 23.2% for 2021 and 2020, respectively. Details of the District's Wholesale Power Contracts are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts,* in the Notes to Financial Statements.

The following chart shows the District's average retail cents per kWh for the years ended December 31, 2018 through 2022. The chart also shows average cents per kWh sold less customer collections for taxes and transfers to other governments, which are not included in the District's base rates for retail customers. The decrease in the average cents per kWh sold was due to a 9.2% and 41.3% increase in industrial energy sales in 2022 and 2021, respectively, from the prior year, as industrial energy sales have the lowest rates of all the retail customer classes.



The following chart shows the District's average wholesale cents per kWh for the years ended December 31, 2018 through 2022. The decrease in the average cents per kWh sold in 2022 from 2021 was due to a 5.1% increase in energy sales. The decrease in the average cents per kWh sold in 2021 from 2020 was due to a 1.2% increase in energy sales and a higher Production Cost Adjustment ("PCA") refund.



Participation Sales, Capacity Sales and Other Sales

There are participation sales agreements in place with other utilities for the sale of power and energy at wholesale from specific generating plants. Such sales are to the City of Lincoln, Nebraska ("Lincoln"), Municipal Energy Agency of Nebraska ("MEAN"), OPPD, and Grand Island Utilities ("Grand Island"). The District also sells capacity and energy on a nonfirm basis in SPP and through transactions executed with other utilities by The Energy Authority ("TEA").

Transmission Customers

The District owns and operates 5,376 miles of transmission and subtransmission lines, encompassing nearly the entire State of Nebraska. The District became a transmission owning member of SPP, a regional transmission organization, in 2009. The District files a rate with SPP annually that provides for the recovery of all transmission revenue requirements associated with transmission facilities equal to or greater than 115 kV. SPP collects and reimburses the District for the use of the District's transmission facilities by entities other than the District's firm requirements customers and all transmission customers still served directly by the District through grandfathered Transmission Agreements.

Customers, Energy Sales, and Revenues

The following table shows customers, energy sales and peak loads of the System, including participation sales, in each of the three years, 2020 through 2022.

			Megawatt-Hour Sales				Peak Load (MW)
Calendar Year	Average Number of Retail Customers	Wholesale Customers(1)	Native Load Sales(2)	Percentage Growth(4)	Total Sales (3)	Percentage Growth(4)	Busbar Native Load
2020	92,267	75	12,448,525	2.3	18,904,111	(8.3)	2,820.5
2021	92,948	75	13,119,624	5.4	19,413,835	2.7	2,904.4
2022	93,485	67	13,854,281	5.6	18,947,050	(2.4)	2,946.0

(1) For 2022, this includes sales to firm wholesale customers, participation customers (Lincoln, MEAN, OPPD and Grand Island), capacity customers and nonfirm customers. The decrease in the number of wholesale customers by eight in 2022 from 2021 was due to the contract term ending for nine customers who limited their requirements under the 2002 contracts and the addition of a capacity sale to Associated Electric Cooperative Inc. (AECI).

(2) Native load sales include retail and wholesale sales to total firm requirements customers and the responsibility of replacement power being procured by the District if the District's generating assets are not operating. Predominantly, native load customers are served under long-term total requirements contracts. The increase in native sales from 2021 to 2022 was due primarily to higher retail industrial energy sales and a weather-related increase in other retail and wholesale energy sales. The increase from 2020 to 2021 was due primarily to an increase of 41.3% in retail industrial energy sales and a 1.2% increase in wholesale energy sales.

(3) Total sales from the System include sales to Lincoln from Gerald Gentleman Station; to MEAN, OPPD and Grand Island from Ainsworth Wind Energy Facility, which sales commenced October 1, 2005, and terminate on September 30, 2025; to OPPD, MEAN, Lincoln and Grand Island from Elkhorn Ridge Wind Facility, which sales commenced March 1, 2009, and terminate on February 28, 2029; to MEAN from Gerald Gentleman Station and Cooper Nuclear Station, which sale commenced January 1, 2011, and terminate on December 31, 2023; to MEAN, Lincoln and Grand Island from Laredo Ridge Wind Facility, which sales commenced February 1, 2011, and terminate on January 31, 2031; to OPPD, Lincoln and Grand Island from Broken Bow I Wind Facility, which sales commenced December 1, 2012, and terminate on November 30, 2032; to OPPD, Lincoln and MEAN from Crofton Bluffs Wind Facility, which sales commenced November 1, 2012, and terminate on October 31, 2032; and to OPPD from Broken Bow II Wind Facility which sales commenced October 1, 2014, and terminate on September 30, 2039.

(4) See (2) for explanations for the change in native load sales. The decrease in percentage growth for total sales from 2021 to 2022 was due primarily to a decrease in nonfirm energy sales as a result of the Cooper Nuclear Station planned refueling and maintenance outage and other fossil station outages. The increase in percentage growth for total sales from 2020 to 2021 was due to the additional native load sales. There was a 2.2% decrease in off-system or nonfirm sales from 2020 to 2021.

FINANCIAL INFORMATION

The following tables summarize the District's financial position and operating results.

CONDENSED STATEMENTS OF NET POSITION (in 000's)

As of December 31,	2022	2021	2020
Current Assets	$ 956,453	$ 1,027,068	$ 884,104
Special Purpose Funds	692,419	788,842	824,572
Utility Plant, Net	2,560,296	2,518,593	2,571,381
Other Long-Term Assets	278,312	276,219	275,517
Deferred Outflows of Resources	272,886	149,550	101,751
Total Assets and Deferred Outflows	$ 4,760,366	$ 4,760,272	$ 4,657,325
Current Liabilities	$ 238,192	$ 180,338	$ 309,371
Long-Term Debt	1,114,249	1,283,134	1,345,408
Other Long-Term Liabilities	868,019	828,362	792,188
Deferred Inflows of Resources:			
Unearned Revenues	267,758	268,096	201,589
Other Deferred Inflows	303,907	313,062	254,552
Net Position	1,968,241	1,887,280	1,754,217
Total Liabilities, Deferred Inflows, and Net Position	$ 4,760,366	$ 4,760,272	$ 4,657,325

CONDENSED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION (in 000's)

For the years ended December 31,	2022	2021	2020
Operating Revenues	$ 1,196,972	$ 1,221,778	$ 1,103,149
Operating Expenses	(1,079,904)	(1,064,354)	(1,011,837)
Operating Income	117,068	157,424	91,312
Investment and Other Income (Loss)	(10,194)	14,608	51,629
Debt and Related Expenses	(25,913)	(38,969)	(47,049)
Increase in Net Position	$ 80,961	$ 133,063	$ 95,892

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2022	2021	2020
Firm Retail and Wholesale Sales	$ 819,768	$ 783,675	$ 778,435
Participation and Capacity Sales	86,006	66,702	64,731
Other Sales	197,395	386,641	106,312
Other Operating Revenues	72,465	72,267	71,760
Unearned Revenues	21,338	(87,507)	81,911
Total Operating Revenues	$ 1,196,972	$ 1,221,778	$ 1,103,149

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2022	2021	2020
Net Cash Provided by Operating Activities	$ 227,742	$ 419,907	$ 205,431
Net Cash Provided by (Used in) Investing Activities	93,257	(94,413)	128,242
Net Cash Used in Capital and Financing Activities	(336,659)	(314,472)	(326,151)
Net Increase (Decrease) in Cash and Cash Equivalents	(15,660)	11,022	7,522
Cash and Cash Equivalents, Beginning of Year	34,789	23,767	16,245
Cash and Cash Equivalents, End of Year	$ 19,129	$ 34,789	$ 23,767

The decrease in net cash provided by operating activities in 2022 from 2021 was because of larger cash inflows in 2021 due primarily to the higher net revenues related to the February 2021 extreme weather event. The increase in cash used for capital and related financing activities in 2022 over 2021 was due primarily to purchases of nuclear fuel inventory. The increase in net cash provided by operating activities in 2021 was due primarily to SPP financial transactions, most of which were related to the February extreme weather event.

Revenues from Firm Retail and Wholesale Sales

The District allocates costs between retail and wholesale service and establishes its rates to produce revenues sufficient to meet its estimated respective retail and wholesale revenue requirements. Wholesale revenue requirements include unbundled costs accounted for separately between generation and transmission. The rates for retail service include an amount to recover the costs of wholesale power service in addition to distribution system costs. 2022 marked the ninth consecutive year with no retail base rate increases and the fifth consecutive year with no wholesale base rate increases.

The District's wholesale power contracts provide for the establishment of cost-based rates. Such rates can be adjusted at such times as deemed necessary by the District. The wholesale power contracts also provide for the creation of a rate stabilization account. Any surplus or deficiency between revenues and revenue requirements, within certain limits set forth in the wholesale power contracts, may be retained or withdrawn through the rate stabilization account. Any amounts in excess of the limits will be included as an adjustment to revenue requirements in the next rate review. The wholesale power contracts also include a provision for establishing a new/replacement generation fund. This provision would permit the District to collect an additional 0.5 mills per kWh above the normal revenue requirements to be used for future capital expenditures associated with generation.

The District implemented a 12-month PCA rate to refund amounts to its wholesale customers for production rate stabilization funds in excess of the 10% accumulated limit. The refunds amounted to $33.9 million, $74.2 million and $73.2 million beginning February 1, 2023, 2022 and 2021, respectively. The PCA equated to a one-year average bill reduction for wholesale customers of 4.4%, 10.1% and 10.2%, compared to base rates for the respective 12-month periods beginning February 1, 2023, 2022 and 2021. The PCA also resulted in an average annual decrease for retail customers of 2.2%, 3.9% and 3.9% compared to base rates for the respective 12-month periods beginning February 1, 2023, 2022 and 2021. Details of the District's Retail and Wholesale Power Contracts are included in Note 12.C., *Retail Agreements and Wholesale Power Contracts,* in the Notes to Financial Statements.

Revenues from firm sales increased $36.1 million, or 4.6%, from $783.7 million in 2021 to $819.8 million in 2022. The increase was due primarily to higher retail industrial energy sales and a weather-related increase in other retail and wholesale energy sales. Revenues from firm sales increased $5.3 million, or 0.7%, from $778.4 million in 2020 to $783.7 million in 2021. The increase in revenues was due primarily to higher retail industrial and wholesale energy sales.

Revenues from Participation and Capacity Sales

Revenues from participation sales increased from $66.7 million in 2021 to $86.0 million in 2022, an increase of $19.3 million, or 28.9%. The increase was due primarily to additional capacity sales, including capacity sales from a 2022 agreement, which expired on December 31, 2022. Revenues from participation sales increased from $64.7 million in 2020 to $66.7 million in 2021, an increase of $2.0 million, or 3.1%. The increase was due primarily to higher demand revenues from participants for Gerald Gentleman Station.

Revenues from Other Sales

Other sales consist of sales in SPP's Integrated Market and nonfirm sales to other utilities. Other sales decreased from $386.6 million in 2021 to $197.4 million in 2022, a decrease of $189.2 million, or 48.9%. The decrease was due primarily to the February 2021 extreme weather event and also generating station outages in 2022, including the planned refueling and maintenance outage at the Cooper Nuclear Station. Other sales increased from $106.3 million in 2020 to $386.6 million in 2021, an increase of $280.3 million, or 263.7%. The increase was due primarily to SPP financial transactions, most of which were related to the high SPP market prices during the February extreme weather event.

Other Operating Revenues

Other operating revenues consist primarily of revenues for transmission and other miscellaneous revenues. These revenues were $72.5 million, $72.3 million and $71.8 million in 2022, 2021 and 2020, respectively. The majority of these revenues were from SPP transmission customers.

Unearned Revenues

Under the provisions of the District's wholesale power contracts, any surplus or deficiency between net revenues and revenue requirements, within certain limits set forth in the wholesale power contracts, may be adjusted in the rate stabilization account. Any amounts in excess of the rate stabilization limits may be included as an adjustment to revenue requirements in the next rate review. A similar process is followed in accounting for any surplus or deficiency in revenues necessary to meet revenue requirements for retail electric service. Under generally accepted accounting principles for regulated electric utilities, the balance of such surpluses or deficiencies are accounted for as regulatory liabilities or assets, respectively.

The District recognizes net revenues in excess of revenue requirements in any year as a deferral or reduction of revenues. Such surplus revenues are excluded from the net revenues available under the General Revenue Bond Resolution ("General Resolution") to meet debt service requirements for such year. Surplus revenues are included in the determination of net revenues available under the General Resolution to meet debt service requirements in the year that such surplus revenues are considered in setting rates. The District recognizes any deficiency in revenues needed to meet revenue requirements in any year as an accrual or increase in revenues, even though the revenue accrual will not be realized as "cash" until some future rate period. Such revenue deficiency is included, in the year accrued, in the net revenues available under the General Resolution to meet debt service requirements for such year. Revenue deficiencies are excluded in the determination of net revenues available under the General Resolution to meet debt service requirements in the year that such revenue deficit is considered in setting rates.

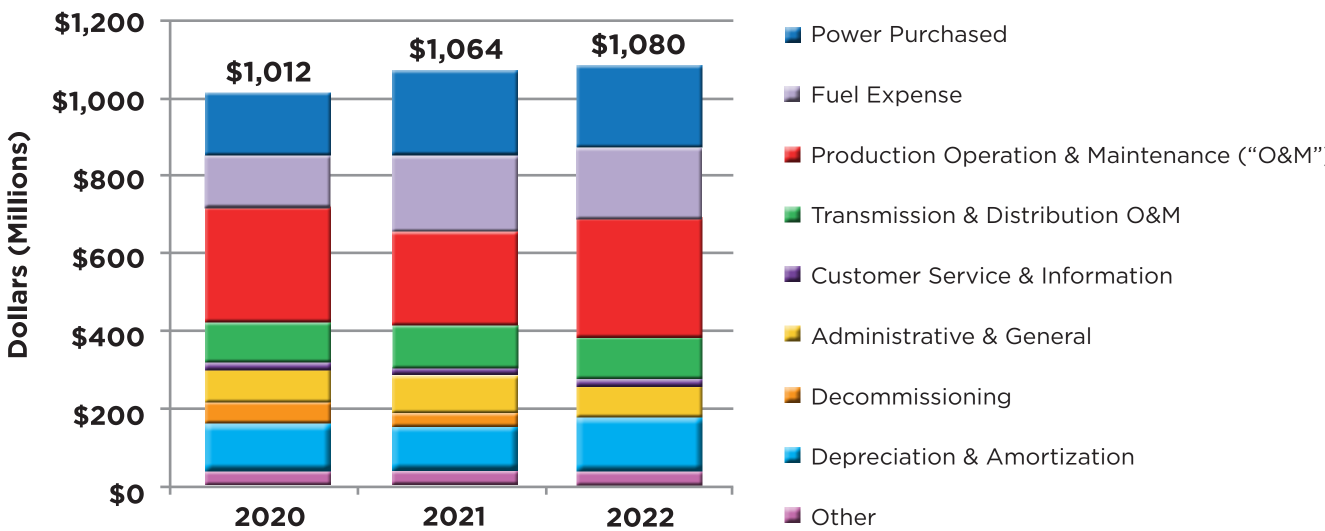
The following table shows the increase (decrease) in revenues from rate stabilization and other regulatory accounts for the years 2022, 2021 and 2020, respectively (in 000's).

	2022	2021	2020
Surplus revenues deferred to future periods	$ (73,822)	$ (144,556)	$ (14,883)
Refunded revenues from prior periods	74,160	78,049	75,794
CNS outage collections	21,000	(21,000)	21,000
	$ 21,338	$ (87,507)	$ 81,911

The balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was $267.8 million, $268.1 million and $201.6 million, as of December 31, 2022, 2021 and 2020, respectively.

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2020 through 2022.



Total operating expenses in 2022 were $1,079.9 million, an increase of $15.6 million over 2021. Total operating expenses in 2021 were $1,064.3 million, an increase of $52.5 million over 2020. The changes were due primarily to the following:

Power purchased expenses were $216.9 million, $219.9 million and $168.2 million in 2022, 2021 and 2020, respectively. These expenses decreased $3.0 million in 2022 from 2021 due primarily to lower costs in 2022 from the SPP Integrated Market and hydro purchases, which were partially offset by higher costs for wind agreements. Power purchased expenses increased $51.7 million in 2021 over 2020 due primarily to additional expenses from the SPP Integrated Market related to the February 2021 extreme weather event and demand charges for NC2, which were partially offset by reduced expenses for the wind agreements.

Fuel expenses were $175.4 million, $198.7 million and $141.6 million in 2022, 2021 and 2020, respectively. These expenses decreased $23.3 million in 2022 from 2021 due primarily to lower costs for the Cooper Nuclear, Beatrice and Canaday Stations, which were partially offset by higher costs for the Gerald Gentleman and Sheldon Stations. The lower costs for the Beatrice and Canaday Stations in 2022 were because of higher costs in 2021 related to the February extreme weather event. The lower costs for the Cooper Nuclear Station were because of the 2022 planned refueling and maintenance outage. The increase in fuel expenses at the Gerald Gentleman Station and Sheldon Station in 2022 was due to higher generation at these facilities. Fuel expenses increased $57.1 million in 2021 from 2020 due primarily to natural gas and fuel oil purchases at high prices during the February 2021 extreme weather event and additional coal expenses in 2021 for higher generation from this fuel source.

Production operation and maintenance expenses were $300.3 million, $230.1 million and $271.6 million in 2022, 2021 and 2020, respectively. These expenses increased $70.2 million in 2022 over 2021 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station, outage maintenance at Gerald Gentleman Station, and higher net expenses from TEA. These expenses decreased $41.5 million in 2021 from 2020 due primarily to the planned refueling and maintenance outage at Cooper Nuclear Station in 2020 and expense reductions realized from TEA related to the February extreme weather event in 2021. These decreases in expenses were partially offset by higher operations and maintenance costs incurred for Gerald Gentleman Station, Sheldon Station and Canaday Station related to increased generation and outage work in 2021.

Transmission and distribution operation and maintenance expenses were $116.0 million, $112.3 million and $106.7 million in 2022, 2021 and 2020, respectively. These costs increased $3.7 million in 2022 from 2021 due primarily to increased costs for SPP expenses, outside services and fleet expenses. Transmission and distribution operation and maintenance expenses increased $5.6 million in 2021 as compared to 2020 due primarily to additional SPP expenses.

Customer service and information expenses were $16.8 million, $15.6 million and $16.1 million in 2022, 2021 and 2020, respectively.

Administrative and general expenses were $83.2 million, $100.8 million and $90.7 million in 2022, 2021 and 2020, respectively. These expenses decreased $17.6 million in 2022 from 2021 due primarily to a reduction in Other Postemployment Benefit ("OPEB") expenses. These expenses increased $10.1 million in 2021 over 2020 due primarily to higher costs for salaries and benefits, outside services and settlements for injuries and damages, along with lower capitalization of these costs as a result of lower capital expenditures in 2021.

Payments to retail communities were $32.6 million, $30.1 million, and $28.3 million in 2022, 2021 and 2020, respectively. These payments were collected from retail customers in communities with PRO Agreements and remitted to the communities. These payments increased $2.5 million in 2022 over 2021 and $1.8 million in 2021 over 2020 due primarily to higher retail sales revenues and an increase in the percentage of revenues collected for certain communities.

Decommissioning expenses were $0, $25.2 million and $52.7 million in 2022, 2021 and 2020, respectively. Decommissioning expenses are recorded in an amount equivalent to the income on investments for decommissioning plus amounts collected for decommissioning in the rates for electric service in such year. Decommissioning expenses were $0 in 2022 because investment losses due to adverse market conditions offset rate collections for the decommissioning of non-nuclear assets. Decommissioning expenses decreased $27.5 million in 2021 as compared to 2020 due primarily to a decrease in investment income for decommissioning funds.

Depreciation and amortization expenses were $128.8 million, $121.8 million and $126.2 million in 2022, 2021 and 2020, respectively. The $7.0 million increase from 2021 to 2022 was due primarily to the amortization of the regulatory asset for OPEB as rate collections began in 2022 for debt service on the debt used to partially fund the OPEB Trust and an increase in depreciation expense for the Ainsworth Wind Facility. These increases were partially offset by lower depreciation expense for Gerald Gentleman Station and lower amortization costs related to assets of retail customers. The decrease of $4.4 million in 2021 from 2020 was due primarily to lower depreciation and amortization costs related to retail customers.

Payments in lieu of taxes were $10.2 million, $9.9 million and $9.8 million in 2022, 2021 and 2020, respectively. The District makes payments in lieu of taxes to local political subdivisions as required by the Nebraska Constitution.

Investment and Other Income (Loss)

Investment and other income (loss) were ($10.2) million, $14.6 million and $51.6 million in 2022, 2021 and 2020, respectively. The decrease of $24.8 million in 2022 from 2021 was due primarily to unfavorable market returns in 2022 and favorable market returns in 2021. The decrease of $37.0 million in 2021 from 2020 was due primarily to a decrease in investment income for decommissioning funds and lower interest rates.

Debt and Related Expenses

Debt and related expenses were $25.9 million, $39.0 million and $47.0 million in 2022, 2021 and 2020, respectively. The decrease of $13.1 million in 2022 from 2021 was due primarily to lower interest expense on revenue bonds and an increase in bond amortization, which was partially offset by higher interest expense on revolving credit agreements because of higher interest rates. The decrease of $8.0 million in 2021 from 2020 was due primarily to a reduction in interest expense from lower interest rates, a reduction in average debt outstanding and the use of operating funds instead of debt for nuclear fuel purchases.

Increase in Net Position

The increase in net position was $81.0 million, $133.1 million and $95.9 million in 2022, 2021 and 2020, respectively. The change in net position in 2022 decreased $52.1 million from 2021 due primarily to lower rate collections for principal payments for debt service and construction from revenue, amortization of the regulatory asset for OPEB, and investment losses due to adverse market conditions, which were partially offset by higher bond premium amortization. The change in net position in 2021 as compared to 2020 increased $37.2 million and was due primarily to an increase in revenues for principal payments for debt service and construction from revenue.

The Condensed Statements of Revenues, Expenses and Changes in Net Position shown on page 13 provides a summary comparison for the years 2022, 2021 and 2020.

FINANCIAL MANAGEMENT POLICY

The District has a Financial Management Policy (the "Policy"), which is subject to periodic review and revisions by the Board. This Policy represents general financial strategies and procedures that are implemented to demonstrate financial integrity and fiscal responsibility in the management of the District's business and its assets. Employees must abide by all applicable District bylaws, Board resolutions, bond resolutions, federal and state laws, other relevant legal requirements and the Policy.

DEBT SERVICE COVERAGE

Under the Policy, the District has established a minimum debt service coverage ratio on the General Revenue Bonds of 1.5 times the debt service on the General Revenue Bonds. Coverage is provided primarily by the amounts collected in operating revenues for utility plant additions, for principal and interest payments on outstanding revolving credit agreements and for payments to those municipalities served by the District under long-term PRO Agreements. The District's debt service coverage ratios were 2.31, 2.71 and 1.89 in 2022, 2021 and 2020, respectively. The debt service coverage was lower for 2022 than 2021 due primarily to a decrease in net revenues. Net revenues were higher in 2021 due primarily to the recognition of surplus revenues from the February 2021 weather event for additional debt principal payments on the revolving credit agreements. The increase in the 2021 debt service coverage ratio over 2020 was due primarily to additional net revenues and less General System Bonded Debt Service. The District prefers to show all debt service paid from revenues, including debt service on redeemed bonds, even though the General Resolution defines debt service only to include scheduled debt service. Debt service for 2022 included the General Revenue Bonds, 2012 Series B, redeemed in December 2022. If the debt service on the said General Revenue Bonds so redeemed were excluded for 2022, the debt service coverage was 2.76 times for 2022. The debt service coverage for 2020 included debt service on the General Revenue Bonds, 2010 Series C, redeemed in December 2020. If the debt service on the said General Revenue Bonds so redeemed were excluded for 2020, the debt service coverage was 2.36 times for 2020. For additional detail, refer to the Calculation of Debt Service Ratios in the Required Supplementary Information.

FINANCING ACTIVITIES

Good credit ratings allow the District to borrow funds at more favorable interest rates. Such ratings reflect only the view of such rating organizations, and an explanation of the significance of such rating may be obtained only from the respective rating agency. There is no assurance that such ratings will be maintained for any given period of time or that they will not be revised downward or be withdrawn entirely by the respective rating agency if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market prices of bonds.

The District's credit ratings on its General Revenue Bonds were as follows:		
Moody's Investors Service	A1	(stable outlook)
S&P Global Ratings	A+	(stable outlook)
Fitch Ratings	A+	(stable outlook)

The District plans, pursuant to the Policy, to issue separate series of indebtedness, including separate series of General Revenue Bonds, for production projects and for transmission projects. No more than 20.0% of the amount of outstanding indebtedness issued for production projects, calculated at the time of issuance of each series of such indebtedness, or $200.0 million, whichever is less, will be permitted to mature after January 1, 2036, the end of the 2016 Contracts. Transmission indebtedness issued for transmission projects is expected to mature over the useful life of the asset that is being financed. New transmission indebtedness may mature after January 1, 2036, the end of the term of the 2016 Contracts. The District's transmission indebtedness is payable from the revenues received during the term of the 2016 Contracts and from retail sales and transmission revenues received under various SPP tariffs. After January 1, 2036, transmission indebtedness will be payable from revenues to be derived from wholesale and retail customers who use the District's transmission facilities, as well as revenues from various SPP tariffs.

The District may issue additional General Revenue Bonds in 2023 to finance or refinance capital costs for its capital improvement plan. The District may at any time also issue bonds to refund any existing indebtedness. The District expects to continue to finance with indebtedness a prior year SPP Notification to Construct capital project for approximately 226 miles of 345 kV transmission line (the "R-Project"), which has an SPP approved estimated cost of $462.7 million. If the updated District cost estimate exceeds the SPP escalated baseline by more than 20%, the District would need to seek approval from SPP. The District previously issued General Revenue Bonds, 2020 Series A, to finance a portion of the costs of the R-project. These bonds are being refunded as part of the 2023 Series A issuance. The District also expects to continue to finance with indebtedness prior year SPP Notification to Construct capital projects related to transmission expansions for the Monolith production facility.

The District also uses tax-exempt and taxable revolving credit agreements for financing needs, ("TERCA" and "TRCA"), respectively. The Board authorized additional TERCA principal payments of $60.0 million in 2021 for the Production level of service due to the favorable financial performance in 2021. Details of the District's debt balances and activity are included in Note 7 in the Notes to Financial Statements.

CAPITAL REQUIREMENTS

The Board-approved capital projects totaled approximately $94.4 million, $163.4 million and $94.9 million in 2022, 2021 and 2020, respectively. The District's capital requirements are funded with monies generated from operations, debt proceeds and other available reserve funds.

Capital projects for 2022 included:

- $9.2 million for transmission line breaker and relay replacements
- $7.2 million for Gerald Gentleman Station 316(b) environmental modifications
- $7.0 million for Cooper Nuclear Station condenser replacement
- $6.4 million for SCADA and Outage Management System integrated technology solution implementation/ upgrade
- $5.3 million for 345kV and 115kV line and substation upgrades
- $4.9 million for April and June 2022 storm damage
- $3.6 million for Firth substation and capacitor bank, an SPP Notification to Construct Project

Capital projects for 2021 included:

- $70.4 million for 345kV and 115kV line and substation additions and upgrades
- $14.5 million for SAP S/4HANA and SAP Analytics Cloud Planning technical software upgrades and advancements
- $7.8 million for Cooper Nuclear Station 316(b) environmental modifications
- $4.9 million for North Platte Hydro penstock exterior coating
- $4.9 million for physical access control system ("PACS") software/card readers/biometrics
- $4.1 million for hydraulic Keystone gate recoating
- $4.0 million for Pauline to Mark Moore transmission line conductor replacement
- $3.0 million for July 2021 storm damage

Capital projects for 2020 included:

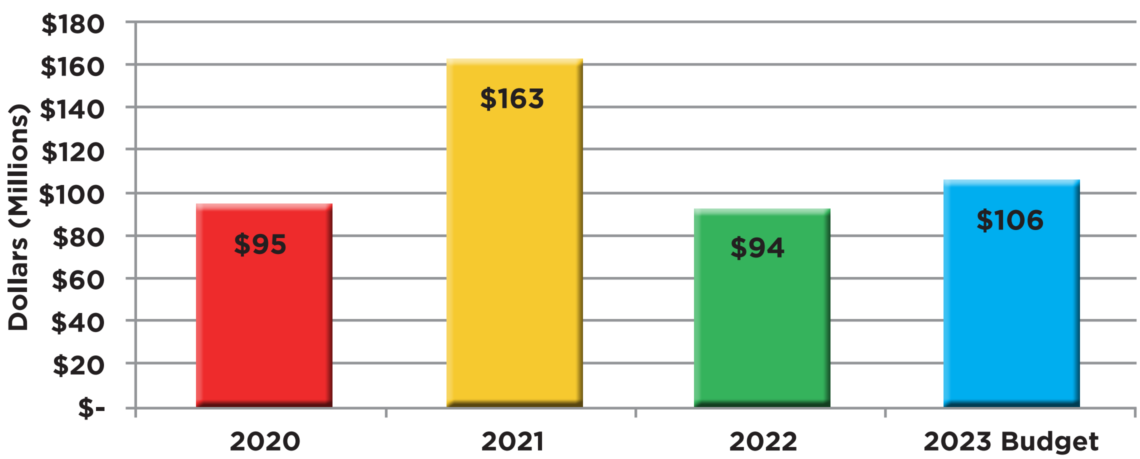
- $17.6 million for the Kearney Tech oNE transmission line and substation projects
- $11.4 million for a generator stator rewind at Gerald Gentleman Station Unit No. 2
- $3.6 million for a generator stator rewind at Beatrice Power Station

There were other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements of $50.8 million, $49.8 million and $62.3 million for 2022, 2021 and 2020, respectively.

The Board-approved budget for capital projects for 2023 is $105.8 million. Specific capital projects for 2023 include:

- $11.9 million for Gerald Gentleman Station boiler tube replacement
- $7.6 million for Cooper Nuclear Station condenser replacement
- $5.4 million for Columbus East 115 transformer upgrade
- $4.4 million for Sheldon Station condenser and dewatering bins replacement/upgrade
- $4.0 million for transmission line breaker and relay replacement
- $3.8 million for technical software upgrades to payroll, time and attendance

The following chart illustrates the Board-approved capital projects for the years ended December 31, 2020 through 2022, including the Board-approved budget for the year ended December 31, 2023.



TRANSMISSION LINE – THE R-PROJECT

The District received an SPP Notification to Construct (NTC) for the R-Project, which allows the cost of construction to be included in SPP annual revenue requirements. The R-Project consists of the construction of approximately 226 miles of 345 kV transmission line from Gerald Gentleman Station, north to a substation east of Thedford, then eastward to a new substation in Holt County interconnected to an existing 345 kV line owned by Western. The R-Project will strengthen the reliability of the District's transmission system, reduce transmission congestion, and allow for the integration of future renewable generation in an area of the state that lacks sufficient transmission access. Additional information on the R-Project is in the Notes to Financial Statements, specifically Note 12.D., *SPP Membership and Transmission Agreements,* and Note 12.F., *Environmental, Endangered Species Act*.

TRANSMISSION LINE PROJECTS – KEARNEY AND SCOTTSBLUFF

The District has accepted SPP NTC for two new 115 kV transmission lines and associated substation terminal modifications. The Kearney 115 kV Transmission line extends from the TechOne substation to the Tower substation in Kearney, Nebraska and is approximately 9 miles in length. The second 115 kV transmission line, which is in the Scottsbluff area and extends from the Scottsbluff substation to the Victory Hill substation, is approximately 10 miles long. Both projects are being built to support local load growth and to relieve congestion on the transmission system. The projects are currently in the line-routing phase with construction activities planned to begin in November 2024 with an in-service date for both projects of May 2025. The expected combined cost for both projects is $31.0 million. The projects will be Base Plan funded in accordance with the SPP Tariff. The Annual Transmission Revenue Requirement will be determined in accordance with the SPP Tariff and allocated 1/3 to the SPP Region and 2/3 to the District's Transmission Pricing Zone. The District expects to recover approximately $13.0 million of these NTC costs from other SPP members. The balance of $18.0 million will be recovered through the District's transmission rates.

MONOLITH MATERIALS, INC.

Monolith Materials, Inc., ("Monolith") is a retail industrial customer of Norris Public Power District, a firm wholesale customer of the District. Monolith produces carbon black at their Olive Creek facility, which became fully operational in 2020. Monolith plans to expand the facility. The District and Monolith executed a Letter of Intent ("the LOI") outlining the interest of the parties to supply Renewable Energy Credits ("REC") for Monolith's facilities. The LOI is subject to termination by either party as provided in the LOI. Pursuant to the LOI, the District solicited bids from renewable energy developers in 2021. The LOI contemplates that the District would enter into power purchase agreements with the renewable energy resource developers and for the District and Monolith to enter into agreements that would provide the methodology for reimbursement of the District's cost of purchasing such energy and REC. Due to numerous uncertainties including potential federal legislation, supply chain issues, regulatory approvals and other factors, the District and Monolith continue to evaluate the process for the purchase of renewable energy and REC. The District will also need to invest in additional transmission facilities for the Olive Creek facility expansion. The District received an NTC from SPP for some of the transmission facilities required for the expansion.

SUPPLY CHAIN DISRUPTION ISSUES

The District, like many other electric utilities, experienced supply chain disruption issues at the end of 2021 and these issues have continued for certain materials and supplies. These supply chain issues have been attributed to adverse impacts on production outputs related to COVID-19, the Russia-Ukraine conflicts, and other factors. As a result of these supply chain issues, delays may be experienced in completing certain projects and work activities.

TERMINATION OF AGREEMENT WITH ENTERGY

The District and Entergy Corporation ("Entergy") mutually terminated the Entergy Agreement for support services at Cooper Nuclear Station on July 31, 2022. The agreement had been in place since 2003. The District has retained, pursuant to the Entergy Agreement, the Operating License for Cooper Nuclear Station and the majority of the full-time employees have remained employees of the District. As a result of the termination, the District hired the Chief Nuclear Officer as a District employee. Additional information is in the Notes to Financial Statements, specifically Note 12.E., *Cooper Nuclear Station.*

RESOURCE PLANNING

The District uses a diverse mix of generation resources such as coal, nuclear, natural gas, hydro, wind and solar to meet its firm requirement customers' needs. The non-carbon energy resources as a percentage of native load sales were 50.2% and 62.9% for 2022 and 2021, respectively. A five-year Integrated Resource Plan ("IRP") was last approved by the Board in 2018. An updated IRP, with an expected completion date of September 2023, was reviewed by the Board in January 2023. The IRP will take into consideration the District goal, which was approved by the Board in 2021, for net zero carbon emissions from generation resources by 2050, while maintaining affordability, reliability and system resiliency. The updated IRP is for a 30-year time period and the major variables include CO_2, load and market uncertainty.

ENERGY MARKET RISK MANAGEMENT PRACTICES

The nature of the District's business exposes it to a variety of risks, including exposure to volatility in electric energy and fuel prices, uncertainty in load and resource availability, the creditworthiness of its counterparties, and the operational risks associated with transacting in the wholesale energy markets. To help manage energy risks, including the risks related to the District's participation in the SPP Integrated Market, the District relies upon TEA to both transact on its behalf in the wholesale energy markets and to develop and recommend strategies to manage the District's exposure to risks in the wholesale energy markets. TEA combines a strong knowledge of the District's system, an in-depth understanding of the wholesale energy markets, experienced people, and state-of-the-art technology to deliver a broad range of standardized and customized energy products and services to the District.

TEA has assisted the District in developing its Energy Market Risk Management ("EMRM") program. The program originates with the Board-approved EMRM Governing Policy and the EMRM-Approved Products and Limits Standard. These documents establish the philosophy, objectives, delegation of authorities, approved products and their limits on the District's energy and fuel activities necessary to govern its EMRM program. The objective of the EMRM program is to increase fuel and energy price stability by hedging the risk of significant adverse impacts to cash flow. These adverse impacts could be caused by events such as natural gas or power price volatility or extended unplanned outages. The EMRM program has been developed to provide assurance to the Board that the risks inherent in the wholesale energy market are being quantified and appropriately managed.

CYBER AND PHYSICAL SECURITY

In the wake of the increased physical attacks nationwide on electrical infrastructure, the District is taking steps to evaluate its current physical security protections for all its critical assets, with a focus on substations. This new round of assessments will result in new recommendations from the team for management to consider to further protect the District's portion of the electrical grid.

The District has a dedicated team of trained staff that is constantly monitoring for any potential cyber threats that may be aimed towards the electric industry and the District. The District has tools in place that help defend against threats and conducts cyber and physical security training for employees to help them identify and respond to these threats.

ECONOMIC FACTORS

Preliminary data indicate that in the past eleven years, 2010 to 2021, Nebraska's inflation-adjusted, estimated gross state product increased, except for one year of decrease between 2019 and 2020. Between the third quarter of 2021 and the third quarter of 2022, estimated gross state product increased by 1.1%. The U.S. economy experienced a 1.9% increase in real national gross domestic product over the same 12-month period.

Declines in Nebraska's "Construction" (-11.8%), "Agriculture, Forestry, Fishing, and Hunting" (-8.4%), "Transportation and Warehousing (-4.6%), and "Mining, Quarrying, and Oil and Gas Extraction" (-2.6%) sectors were offset by increases in "Information" (+17.7%), "Management of Companies and Enterprises" (+14.0%), "Administrative and Support and Waste Management and Remediation Services" (+9.8%), and "Arts, Entertainment, and Recreation" (+9.4%).

Despite strong demand for goods and services in 2022, supply constraints led to higher prices and lost production. These constraints included lack of inputs, due to supply chain disruptions, and labor shortages. Due to a lower labor force participation rate, there was an upward pressure on wages. This upward pressure led to higher rates of inflation in 2022. The average annual inflation rate for 2022 was 8.0% and monthly inflation rates for December 2022 and January 2023 were 6.5% and 6.4%, respectively. Currently, rising gasoline prices spurred by the Russia-Ukraine conflict will challenge economic growth in the U.S. and Nebraska economies in 2022. Into 2023, the U.S. and Nebraska economies will see constraints on growth due to increases in interest rates by the Federal Reserve Bank.

Nebraska and the Midwest region continue to experience unemployment rates below the national average. Nebraska's average annual unemployment rate decreased from the 2021 value of 2.7% to 2.3% in 2022. This was well below the 2022 national average unemployment rate of 3.6%. Nebraska's preliminary, seasonally-adjusted unemployment rate was 2.7% in December 2022, equal to the revised rate of 2.7% in December 2021. Both numbers were well below the national December seasonally-adjusted unemployment rates of 3.5% in 2022 and 3.9% in 2021. Nebraska's preliminary December 2022 unemployment rate ranks third lowest in the nation after North and South Dakota. The District continues to monitor changes in national and global economic conditions, which could impact operating costs, the cost of debt and access to capital markets.

CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY AND THE NATION

The Electric Utility Industry in General

The electric utility industry has been, and in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of electric utilities, such as the District. Such factors include, among others:

- supply chain disruption issues for certain materials and equipment,
- labor shortage issues,
- effects of compliance with changing environmental, safety, licensing, regulatory and legislative requirements,
- changes resulting from energy efficiency and demand-side management programs on the timing and use of electric energy,
- other federal and state legislative and regulatory changes,
- increased wholesale competition from independent power producers, marketers and brokers, and potential aggregation of certain energy products at the retail distribution level for sale into wholesale markets,
- “self-generation” by certain industrial and commercial customers,
- issues relating to the ability to issue tax-exempt obligations,
- severe restrictions on the ability to sell to nongovernmental entities electricity from generation projects financed with outstanding tax-exempt obligations,
- changes from projected future load requirements,
- increases in costs,
- shifts in the availability and relative costs of different fuels,
- inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy, fuel and transmission capacity,
- effects of financial instability of various participants in the power market,
- climate change and the potential contributions made to climate change by coal-fired and other fossil-fueled generating units,
- challenges associated with additional renewable generation, including distributed generation,
- electrification of transportation sectors,
- issues relating to cyber and physical security,
- increasing costs and challenges building electric transmission facilities, and
- growing expectations among some large customers for renewable/clean energy supply options.

Any of these general factors (as well as other factors) could have an effect on the financial condition of the District.

Competitive Environment in Nebraska

While wholesale competition is expected to increase in the future, there is a Nebraska statute that prohibits competition for retail customers. Pursuant to state statutes, retail suppliers of electricity have exclusive rights to serve customers at retail in their respective service territories. Any transfer of retail customers or service territories between retail electric suppliers may be done only upon agreement of the respective retail electric suppliers and/or pursuant to an order of the Nebraska Power Review Board. While state statutes do not provide for wholesale suppliers of electricity to have exclusive rights to serve a particular area or customer at wholesale, wholesale power suppliers are permitted to voluntarily enter into agreements with other wholesale power suppliers limiting the areas or customers to whom they may sell energy at wholesale. The District has entered into several such agreements. Such agreements are only binding upon the parties to the agreement.

Report of Independent Auditors

To the Board of Directors of the Nebraska Public Power District

Opinion

We have audited the accompanying financial statements of the Nebraska Public Power District (the "District"), which comprise the statements of net position – business-type activities and of fiduciary net position – postemployment medical and life benefits plan as of December 31, 2022 and 2021, and the related statements of revenues, expenses, and changes in net position – business-type activities, of changes in fiduciary net position – postemployment medical and life benefits plan, and of cash flows – business type activities for the years then ended, including the related notes (collectively referred to as the District's "basic financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the business-type activities and the fiduciary activities of Nebraska Public Power District as of December 31, 2022 and 2021, and 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 Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the District and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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 District'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.

Auditors' 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 auditors' report that includes our opinion. 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 US GAAS 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 US GAAS, 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 District'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 District'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 Supplemental Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis and supplemental schedules on pages 7 through 22 and 58 through 60 be presented to supplement the basic financial statements. Such information is the responsibility of management, 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 supplemental 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 audit 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 statistical section, but does not include the basic financial statements and our auditors' report thereon. Our opinion on the basic financial statements does 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.

PricewaterhouseCoopers LLP

Chicago, Illinois
April 13, 2023

Statements of Net Position - Business-Type Activities

Nebraska Public Power District

As of December 31, (in 000's)	2022	2021	$ Change
ASSETS AND DEFERRED OUTFLOWS			
Current Assets:			
Cash and cash equivalents	$ 19,129	$ 34,789	$ (15,660)
Investments	619,878	707,295	(87,417)
Receivables, less allowance for doubtful accounts of $532 and $522, respectively	136,906	115,498	21,408
Fossil fuels, at average cost	34,496	31,817	2,679
Materials and supplies, at average cost	129,851	120,830	9,021
Prepayments and other current assets	16,193	16,839	(646)
	956,453	1,027,068	(70,615)
Special Purpose Funds:			
Construction funds	15,148	19,040	(3,892)
Debt service and reserve funds	71,770	73,409	(1,639)
Employee benefit funds	3,048	2,106	942
Decommissioning funds	602,453	694,287	(91,834)
	692,419	788,842	(96,423)
Utility Plant, at Cost:			
Utility plant in service	5,255,397	5,204,057	51,340
Less reserve for depreciation	3,102,840	3,034,216	68,624
	2,152,557	2,169,841	(17,284)
Construction work in progress	260,841	243,245	17,596
Nuclear fuel, at amortized cost	146,898	105,507	41,391
	2,560,296	2,518,593	41,703
Other Long-Term Assets:			
Regulatory asset for other postemployment benefits	41,829	84,273	(42,444)
Long-term capacity contracts	118,105	125,023	(6,918)
Unamortized financing costs	5,087	6,145	(1,058)
Investment in The Energy Authority	26,182	21,821	4,361
Net other postemployment benefit asset	82,038	34,527	47,511
Other	5,071	4,430	641
	278,312	276,219	2,093
Total Assets	4,487,480	4,610,722	(123,242)
Deferred Outflows of Resources:			
Asset retirement obligation	243,014	102,502	140,512
Unamortized cost of refunded debt	2,457	3,214	(757)
Other postemployment benefits	27,415	43,834	(16,419)
	272,886	149,550	123,336
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,760,366	$ 4,760,272	$ 94
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION			
Current Liabilities:			
Revenue bonds, current	$ 105,125	$ 63,535	$ 41,590
Accounts payable and accrued liabilities	78,385	71,754	6,631
Accrued in lieu of tax payments	10,175	9,865	310
Accrued payments to retail communities	2,638	2,391	247
Accrued compensated absences	21,330	20,582	748
Other	20,539	12,211	8,328
	238,192	180,338	57,854
Long-Term Debt:			
Revenue bonds, net of current	965,517	1,123,341	(157,824)
Revolving credit agreements, net of current	148,732	159,793	(11,061)
	1,114,249	1,283,134	(168,885)
Other Long-Term Liabilities:			
Asset retirement obligation	851,819	800,855	50,964
Other	16,200	27,507	(11,307)
	868,019	828,362	39,657
Total Liabilities	2,220,460	2,291,834	(71,374)
Deferred Inflows of Resources:			
Unearned revenues	267,758	268,096	(338)
Other deferred inflows	303,907	313,062	(9,155)
	571,665	581,158	(9,493)
Net Position:			
Net investment in capital assets	1,496,941	1,340,481	156,460
Restricted	21,860	22,194	(334)
Unrestricted	449,440	524,605	(75,165)
	1,968,241	1,887,280	80,961
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	$ 4,760,366	$ 4,760,272	$ 94

The accompanying notes to Financial Statements are an integral part of these statements.

Statements of Revenues, Expenses, and Changes in Net Position - Business-Type Activities
Nebraska Public Power District

For the years ended December 31, (in 000's)	2022	2021
Operating Revenues	$ 1,196,972	$ 1,221,778
Operating Expenses:		
Power purchased	216,946	219,941
Production:		
Fuel	175,432	198,693
Operation and maintenance	300,347	230,096
Transmission and distribution operation and maintenance	115,968	112,318
Customer service and information	16,837	15,554
Administrative and general	83,239	100,785
Payments to retail communities	32,594	30,119
Decommissioning	(479)	25,165
Depreciation and amortization	128,803	121,777
Payments in lieu of taxes	10,217	9,906
	1,079,904	1,064,354
Operating Income	117,068	157,424
Investment and Other Income:		
Investment income (loss)	(12,371)	12,368
Other income	2,177	2,240
	(10,194)	14,608
Increase in Net Position Before Debt and Other Expenses	106,874	172,032
Debt and Related Expenses:		
Interest on revenue bonds	44,627	52,730
Allowance for funds used during construction	(2,428)	(1,492)
Bond premium amortization net of debt issuance expense	(19,264)	(13,315)
Interest on revolving credit agreements	2,978	1,046
	25,913	38,969
Increase in Net Position	80,961	133,063
Net Position:		
Beginning balance	1,887,280	1,754,217
Ending balance	$ 1,968,241	$ 1,887,280

The accompanying notes to Financial Statements are an integral part of these statements.

Statements of Cash Flows - Business-Type Activities

Nebraska Public Power District

For the years ended December 31, (in 000's)	2022	2021
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 1,098,405	$ 1,244,530
Other receipts	188	454
Payments to suppliers and vendors	(577,388)	(552,809)
Payments to employees	(293,463)	(272,268)
Net cash provided by operating activities	227,742	419,907
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	3,905,350	3,809,008
Purchases of investments	(3,802,462)	(3,921,383)
Income received on investments	(10,012)	17,962
Change in cash held in special purpose funds	381	-
Net cash provided by (used in) investing activities	93,257	(94,413)
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of revenue bonds	-	318,623
Proceeds from revolving credit agreements	55,068	131,556
Capital expenditures for utility plant	(193,938)	(128,312)
Contributions in aid of construction and other reimbursements	4,967	21,993
Principal payments on revenue bonds	(95,155)	(490,465)
Interest payments on revenue bonds	(44,627)	(54,773)
Interest paid on defeased revenue bonds	-	(4,877)
Principal payments on revolving credit agreements	(66,129)	(107,681)
Interest payments on revolving credit agreements	(2,585)	(999)
Other non-operating revenues	5,740	463
Net cash used in capital and related financing activities	(336,659)	(314,472)
Net increase (decrease) in cash and cash equivalents	(15,660)	11,022
Cash and cash equivalents, beginning of year	34,789	23,767
Cash and cash equivalents, end of year	$ 19,129	$ 34,789
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 117,068	$ 157,424
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	128,803	121,777
Undistributed net revenue - The Energy Authority	(38)	684
Decommissioning, net of customer contributions	(12,778)	12,752
Amortization of nuclear fuel	29,020	34,726
Changes in assets and liabilities which provided (used) cash:		
Receivables, net	(22,738)	(7,497)
Fossil fuels	(2,679)	(4,189)
Materials and supplies	(9,021)	(5,574)
Prepayments and other current assets	(795)	(1,822)
Accounts payable and accrued payments to retail communities	6,684	6,949
Unearned revenues	(338)	66,507
Other deferred inflows	(7,353)	35,437
Other liabilities	1,907	2,733
Net cash provided by operating activities	$ 227,742	$ 419,907
Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	$ (551)	$ (6,880)

The accompanying notes to Financial Statements are an integral part of these statements.

Statements of Fiduciary Net Position - Postemployment Medical and Life Benefits Plan
Nebraska Public Power District

As of December 31, (in 000's)	2022	2021
Assets:		
Cash and cash equivalents	$ 3,218	$ 29,967
Receivables:		
Investment income	716	467
Investments	322,342	372,177
Total Assets	326,276	402,611
Liabilities:		
Payables:		
Benefits - healthcare	144	44
Benefits - life insurance	74	58
Investment expense	31	31
Professional, administrative and other expenses	117	136
Total liabilities	366	269
Net Position - Restricted for Other Postemployment Benefits	$ 325,910	$ 402,342

The accompanying notes to Financial Statements are an integral part of these statements.

Statements of Changes in Fiduciary Net Position - Postemployment Medical and Life Benefits Plan

Nebraska Public Power District

For the Years Ended December 31, (in 000's)	2022	2021
Additions:		
Contributions		
Employer	$ 6,294	$ 28,283
Investment Income (loss):		
Net appreciation (depreciation) in fair value of investments	(70,654)	43,137
Interest, dividends and other income	6,050	4,028
Total investment income (loss)	(64,604)	47,165
Less: Investment expenses	(1,043)	(686)
Net investment income (loss)	(65,647)	46,479
Total additions	(59,353)	74,762
Deductions:		
Health care benefits	16,598	15,493
Life insurance benefits	269	218
Professional, administrative and other expenses	212	259
Total deductions	17,079	15,970
Increase (Decrease) in Net Position	(76,432)	58,792
Net Position - Restricted for Other Postemployment Benefits		
Beginning balance	402,342	343,550
Ending balance	$ 325,910	$ 402,342

The accompanying notes to Financial Statements are an integral part of these statements.

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

A. *Organization –*
Nebraska Public Power District ("District"), a public corporation and a political subdivision of the State of Nebraska, operates an integrated electric utility system which includes facilities for the generation, transmission and distribution of electric power and energy to its Retail and Wholesale customers. The control of the District and its operations is vested in a Board of Directors ("Board") consisting of 11 members popularly elected from districts comprising subdivisions of the District's chartered territory. The Board is authorized to establish rates.

B. *Basis of Accounting –*
The Financial Statements are prepared in accordance with Generally Accepted Accounting Principles ("GAAP") for accounting guidance provided by the Governmental Accounting Standards Board ("GASB") for proprietary funds of governmental entities. In the absence of established GASB pronouncements, other accounting literature is considered including guidance provided in the Financial Accounting Standards Board ("FASB") Accounting Standards Codification.

The District applies the accounting policies established in the GASB codification Section Re10, *Regulated Operations.* This guidance permits an entity with cost-based rates and Board authorization to include revenues or costs in a period other than the period in which the revenues or costs would be reported by an unregulated entity.

C. *Revenue –*
Retail and wholesale revenues are recorded in the period in which services are rendered. Revenues and expenses related to providing energy services in connection with the District's principal ongoing operations are classified as operating. All other revenues and expenses are classified as non-operating and reported as investment and other income or debt and related expenses on the Statements of Revenues, Expenses and Changes in Net Position.

D. *Cash and Cash Equivalents –*
The operating fund accounts are called Revenue Funds. There is a separate investment account for the Revenue Funds. The District reports highly liquid investments in the Revenue Funds with an original maturity of three months or less to be cash and cash equivalents on the Statements of Net Position, except for these types of investments in the Revenue Funds investment account. Cash and cash equivalents in the investment accounts for the Revenue Funds and the Special Purpose Funds are reported as investments on the Statements of Net Position.

E. *Fossil Fuel and Materials and Supplies –*
The District maintains inventories for fossil fuels and materials and supplies which are valued at average cost. Obsolete inventory is expensed and removed from inventory.

F. *Utility Plant, Depreciation, Amortization, and Maintenance –*
Utility plant is stated at cost, which includes property additions, replacements of units of property and betterments. The District charges maintenance and repairs, including the cost of renewals and replacements of minor items of property, to maintenance expense accounts when incurred. Upon retirement of property subject to depreciation, the cost of property is removed from the utility plant accounts and charged to the reserve for depreciation, net of salvage.

The District records depreciation over the estimated useful life of the property primarily on a straight-line basis. Depreciation on utility plant was approximately 2.0% and 2.1% for the years ended December 31, 2022 and 2021. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station, which was still in service of $1,579.5 million and $1,364.6 million as of December 31, 2022 and 2021, respectively.

The District's retail service territory includes 77 municipal-owned distribution systems operated by the District within the State of Nebraska for the municipality pursuant to a Professional Retail Operations Agreement ("PRO Agreement") and two retail communities in South Dakota. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal property additions during the term of the agreements. The District recorded amortization for these utility plant additions of $7.0 million and $8.0 million in 2022 and 2021, respectively, which was included in depreciation and amortization expense. These utility plant additions, which were fully amortized, totaled $222.2 million and $218.2 million as of December 31, 2022 and 2021, respectively.

G. *Allowance for Funds Used During Construction ("AFUDC")* –
This allowance, which represents the cost of funds used to finance construction, is capitalized as a component of the cost of the utility plant. The capitalization rate depends on the source of financing. The rate for construction financed with revenue bonds is based upon the interest cost of each bond issue less interest income. Construction financed on a short-term basis with the tax-exempt revolving credit agreement ("TERCA") or the taxable revolving credit agreement ("TRCA") is charged a rate based upon the projected average interest cost of the related debt outstanding. For the periods presented herein, the AFUDC rates for construction funded by revenue bonds varied from 0.6% to 3.5%. For construction financed on a short-term basis, the rate was 1.0% for 2022 and 2021.

H. *Nuclear Fuel* –
Nuclear fuel inventories are included in utility plant. The nuclear fuel cycle requirements are satisfied through the procurement of raw material in the form of natural uranium, conversion services of such material to uranium hexafluoride, uranium hexafluoride that has already been converted from uranium, enrichment services, and fuel fabrication and related services. The District purchases uranium and uranium hexafluoride on the spot market and carries inventory in advance of the refueling requirements and schedule. Nuclear fuel in the reactor is being amortized on the basis of energy produced as a percentage of total energy expected to be produced. Fees for disposal of fuel in the reactor are being expensed as part of the fuel cost.

I. *Unamortized Financing Costs* –
These costs include issuance expenses for bonds which are being amortized over the life of the respective bonds using the bonds outstanding method. Deferred unamortized financing costs associated with bonds refunded are amortized using the bonds outstanding method over the shorter of the original or refunded life of the respective bonds. Regulatory accounting, GASB codification section Re10, *Regulated Operations,* is used to amortize these costs over their respective periods.

J. *Asset Retirement Obligations ("ARO")* –
ARO represent the best estimate of the current value of cash outlays expected to be incurred for legally enforceable retirement obligations of tangible capital assets. Regulatory accounting, GASB codification section Re10, *Regulated Operations,* is used to recognize these costs consistent with the rate treatment.

K. *Other Postemployment Benefits ("OPEB")* –
For purposes of measuring the net OPEB asset or net OPEB liability, deferred outflows of resources and deferred inflows of resources related to OPEB, and OPEB expense, information about the fiduciary net position of the District's Postemployment Medical and Life Benefits Plan ("Plan") and additions to/deductions from the Plan's fiduciary net position have been determined on the same basis as they are reported by the Plan. For this purpose, the Plan recognizes benefit payments when due and payable in accordance with the benefit terms. Investments are reported at fair value, except for certain investments in a real estate fund, an international equity fund, and a U.S. equity fund, which are reported at net asset value.

L. *Auction Revenue Rights ("ARR") and Transmission Congestion Rights ("TCR")* –
The District uses ARR and TCR in the Southwest Power Pool ("SPP") Integrated Market to hedge against transmission congestion charges. These financial instruments were primarily designed to allow firm transmission customers the opportunity to offset price differences due to transmission congestion costs between resources and loads. Awarded ARR provide a fixed revenue stream to offset congestion costs. TCR can be acquired through the conversion of ARR or purchases from SPP auctions or secondary market trades. The financial transactions for all ARR/TCR activity in SPP are netted and recorded as other sales, as the District is generally a net seller in SPP. Unearned revenues are recorded for awarded ARR, net of conversion of TCR, until the revenues are realized in the SPP Integrated Market financial transactions. Outstanding TCR positions are recorded on the Statements of Net Position until expired.

M. *Deferred Outflows of Resources and Deferred Inflows of Resources* –
Deferred outflows of resources are consumptions of assets that are applicable to future reporting. Regulatory accounting is used for ARO. The ARO deferred outflow is the difference between the related liability amount and rate collections and the interest earned on decommissioning funds. The deferred outflow for the unamortized cost of refunded debt is the remaining cost to be amortized. Deferred outflows related to OPEB include unrealized contributions and losses.

Deferred inflows of resources are acquired assets that are applicable to future reporting periods and consist of regulatory liabilities for unearned revenues and other deferred inflows. Other deferred inflows include Department of Energy ("DOE") settlements, nuclear fuel disposal collections, Cooper Nuclear Station outage collections, unrealized OPEB gains, settlements for termination of certain power and transmission agreements, non-nuclear decommissioning collections and a sales tax refund from the State of Nebraska for the construction of a renewable energy facility.

The District is required under the General Revenue Bond Resolution ("General Resolution") to charge rates for electric power and energy so that revenues will be at least sufficient to pay operating expenses, aggregate debt service on the General Revenue Bonds, amounts to be paid into the Debt reserve fund and all other charges or liens payable out of revenues. In the event the District's rates for wholesale service result in a surplus or deficit in revenues during a rate period, such surplus or deficit, within certain limits, may be retained in a rate stabilization account. Any amounts in excess of the limits will be considered in projecting revenue requirements and establishing rates in future rate periods. Such treatment of wholesale revenues is stipulated by the District's long-term wholesale power supply contracts. The District accounts for any surplus or deficit in revenues for retail service in a similar manner.

The following table summarizes the balance of Unearned revenues as of December 31, 2022 and 2021 and activity for the years then ended (in 000's):

	2022	2021
Unearned revenues, beginning of year	$ 268,096	$ 201,589
Surpluses	73,822	144,556
Use of prior period rate stabilization funds in rates	(74,160)	(78,049)
Unearned revenues, end of year	$ 267,758	$ 268,096

The DOE settlements regulatory liability was established for the reimbursement from the DOE for costs incurred by the District in conjunction with the disposal of spent nuclear fuel from Cooper Nuclear Station. Details of the District's DOE settlements are included in Note 12.E., *Cooper Nuclear Station,* in the Notes to Financial Statements.

The District includes in rates the costs associated with nuclear fuel disposal. Such collections were remitted to the DOE under the Nuclear Waste Policy Act until the DOE adjusted the spent fuel disposal fee to zero, effective May 16, 2014. The Board authorized the use of regulatory accounting for the continued collection of these costs. This approach ensures costs are recognized in the appropriate period with customers receiving the benefits from Cooper Nuclear Station paying the appropriate costs. The expense for spent nuclear fuel disposal is recorded at the previous DOE rate based on net electricity generated and sold and the regulatory liability will be eliminated when payments are made for spent nuclear fuel disposal. Additional details of the District's DOE spent nuclear fuel collections are included in Note 12.E., *Cooper Nuclear Station,* in the Notes to Financial Statements.

In 2021, the District collected revenues for the costs of the 2022 Cooper Nuclear Station refueling and maintenance outage. This regulatory liability was included in Other deferred inflows on the Statements of Net Position and was amortized through revenue during 2022, the year of the outage.

The District and Heartland Consumers Power District ("Heartland") executed a termination and release agreement in 2018 for certain transmission services. The District and the City of Lincoln, Nebraska ("Lincoln") executed a termination and release agreement in 2017 for the Sheldon Station Participation Agreement. The Board authorized the use of regulatory accounting for these settlement payments. These regulatory liabilities were included in Other deferred inflows on the Statements of Net Position and will be eliminated as the revenues from the settlement payments are incorporated in future rates.

The District collects in rates for non-nuclear decommissioning costs. The collections for assets which do not have a legally required retirement obligation are recorded as a regulatory liability and are included, along with the interest on these funds, in Other deferred inflows on the Statements of Net Position.

The following table summarizes the balance of Other deferred inflows of resources as of December 31, 2022 and 2021 (in 000's):

	2022	2021
DOE settlements	$ 78,312	$ 78,311
Nuclear fuel disposal collections	50,643	45,412
CNS outage collections	-	21,000
Settlements for termination of agreements	26,093	30,456
Unrealized OPEB gains	93,964	93,481
Non-nuclear decommissioning collections	51,808	41,032
Renewable energy facility sales tax refund	3,087	3,370
	$ 303,907	$ 313,062

N. *Net Position –*
Net position is made up of three components: Net investment in capital assets, Restricted and Unrestricted.

Net investment in capital assets consisted of utility plant assets, net of accumulated depreciation and reduced by the outstanding balances of any bonds or revolving credit agreements that are attributable to the acquisition, construction, or improvement of these assets. This component also included long-term capacity contracts, net of the outstanding balances of any bonds or revolving credit agreements attributable to these assets.

Restricted net position consisted of the Primary account in the Debt reserve funds that are required deposits under the General Resolution and the Decommissioning funds, net of any related liabilities.

Unrestricted net position consisted of any remaining net position that does not meet the definition of Net investment in capital assets or Restricted and is used to provide for working capital to fund fuel and inventory requirements, as well as other operating needs of the District.

O. *Use of Estimates –*
The preparation of Financial Statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect 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 could differ from those estimates.

P. *Recent Accounting Pronouncements –*
GASB Statement No. 87, *Leases,* was issued in June 2017. For certain operating leases, lessees are required to recognize an asset for the right to use the leased item and a corresponding lease liability. These lease liabilities are considered long-term debt and lease payments are capital financing outflows in the cash flow statement. In the activity statement, lessees will no longer report rent expense for certain operating-type leases; but will instead report interest expense on the liability and amortization expense related to the asset. For lessors, the accounting will mirror lessee accounting. Lessors will recognize a lease receivable and a corresponding deferred inflow of resources (with certain exceptions), while continuing to report the asset underlying the lease. Interest income associated with the receivable will be recognized using the effective interest method. Lease revenue will arise from amortizing the deferred inflow of resources in a systematic and rational manner over the lease term. In March 2020, the Board authorized the use of regulatory accounting to continue the revenue and expense recognition for leases consistent with the rate methodology as used for the District's customers. The requirements of this Statement were implemented, using regulatory accounting, in 2022. There were no lease agreements for the District, either as a lessor or lessee, that met the requirements for lease accounting under this new guidance as of December 31, 2022.

GASB Statement No. 93, *Replacement of Interbank Offered Rates*, was issued in March 2020. As a result of global reference rate reform, the London Interbank Offered Rate ("LIBOR") is scheduled to cease to exist in its current form in 2023. This Statement addresses the accounting and financial reporting effects that result from the replacement of interbank offered rates with other references rates. The District transitioned from LIBOR to the Securities Industry and Financial Markets Association (SIFMA) as a reference rate on the tax-exempt revolving credit agreements on September 15, 2022. The District will replace LIBOR as a reference rate on the taxable revolving credit agreement to the Secured Overnight Financing Rate (SOFR) in 2023.

GASB Statement No. 96, *Subscription-Based Information Technology Arrangements*, was issued in May 2020. This Statement establishes accounting and financial reporting requirements for subscription-based information technology arrangements ("SBITA") as no such guidance previously existed. SBITAs are arrangements in which the District has access to vendors' information technology ("IT") software and associated tangible capital assets for subscription payments but does not have a perpetual license or title to the IT software and associated tangible assets. The requirements of this Statement are effective for fiscal years beginning after June 15, 2022. Management will implement the requirements of this Statement in 2023.

GASB Statement No. 101, *Compensated Absences,* was issued in June 2022. The District currently recognizes liabilities for unused vacation benefits earned by employees. This Statement requires the recognition of additional liabilities for certain compensated absences, like sick leave, regardless of whether the sick leave benefit is vested or not vested. Currently, there are not any liabilities for sick leave recognized on the District's financial statements as the sick leave benefits are not vested. This Statement will result in the recognition of additional liabilities on the District's financial statements for non-vested employee sick leave benefits. The District is evaluating the impact from the implementation of this Statement, which has an effective date for fiscal years beginning after December 15, 2023.

2. CASH AND INVESTMENTS:

Investments are recorded at fair value with the changes in the fair value of investments reported as Investment income in the accompanying Statements of Revenues, Expenses, and Changes in Net Position. The District had an unrealized net loss of $8.4 million in 2022 and an unrealized net loss $3.0 million in 2021, respectively.

The fair value of all cash and investments, regardless of classification on the Statements of Net Position, was as follows as of December 31 (in 000's):

	2022		2021	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities	$ 1,006,411	3.8	$ 943,442	3.5
Corporate bonds	177,409	14.1	221,767	15.3
Municipal bonds	10,106	14.5	9,951	13.9
Cash and cash equivalents	137,500	0.0	355,766	0.2
Total cash and investments	$ 1,331,426		$ 1,530,926	
Portfolio weighted average maturity		4.8		4.5

Interest Rate Risk – The investment strategy for all investments, except for the decommissioning funds, is to buy and hold securities until maturity, which minimizes interest rate risk. The investment strategy for decommissioning funds is to actively manage the diversification of multiple asset classes to achieve a rate of return equal to or exceeding the rate used in the decommissioning funding plan model assumptions. Accordingly, securities are bought and sold prior to maturity to increase opportunities for higher investment returns.

Credit Risk – The District follows a Board-approved Investment Policy. This policy complies with state and federal laws, and the General Resolution's provisions governing the investment of all funds. The majority of investments are direct obligations of, or obligations guaranteed by, the United States of America. Other investments are limited to investment-grade fixed income obligations.

Custodial Credit Risk – Cash deposits, primarily interest bearing, are covered by federal depository insurance, pledged collateral consisting of U.S. Government Securities held by various depositories, or an irrevocable, nontransferable, unconditional letter of credit issued by a Federal Home Loan Bank.

The fair values of the District's Revenue and Special Purpose Funds as of December 31 were as follows (in 000's):

The Revenue funds are used for operating activities for the District. Cash and cash equivalents in the Revenue funds are reported as such on the Statements of Net Position, except Cash and cash equivalents in the Revenue Fund investment account are reported as Investments.

	2022	2021
Revenue funds - Cash and cash equivalents	$ 19,129	$ 34,789
Revenue funds - Cash equivalents in investments	107,059	305,161
Revenue funds - Investments	512,819	402,134
	$ 639,007	$ 742,084

The Construction funds are used for capital improvements, additions, and betterments to and extensions of the District's system. The sources of monies for deposits to the Construction funds are from General Revenue Bond proceeds and the issuance of short-term debt.

	2022	2021
Construction funds - Cash and cash equivalents	$ -	$ 381
Construction funds - Investments	15,148	18,659
	$ 15,148	$ 19,040

The Debt service and reserve funds are established under the General Resolution. The Debt service funds are used for the payment of debt service. The Debt reserve funds consist of a Primary account and a Secondary account. The District is required by the General Resolution to maintain an amount equal to 50% of the maximum amount of interest accrued in the current or any future year in the Primary account. Such amount totaled $21.9 million and $22.2 million as of December 31, 2022 and 2021, respectively. The Secondary account can be established at such amounts and can be utilized for any lawful purpose as determined by the District's Board. Such account totaled $49.9 million and $51.2 million as of December 31, 2022 and 2021.

	2022	2021
Debt service and reserve funds - Investments	$ 71,770	$ 73,409

The Employee Benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2022 and 2021. The District pays 85% of the hospital-medical premiums with the employees paying the remaining 15% of the cost of such coverage.

	2022	2021
Employee benefit funds - Cash and cash equivalents	$ 3,048	$ 2,106

The Decommissioning funds are utilized to account for the investments held to fund the estimated cost of decommissioning Cooper Nuclear Station when its operating license expires. The Decommissioning funds are held by outside trustees or custodians in compliance with the decommissioning funding plans approved by the Board which are invested primarily in fixed income governmental securities.

	2022	2021
Decommissioning funds - Cash and cash equivalents	$ 8,264	$ 13,328
Decommissioning funds - Investments	594,189	680,959
	$ 602,453	$ 694,287

3. FAIR VALUE OF FINANCIAL INSTRUMENTS:

Fair value is the exchange price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date.

GASB Codification Section 3100, *Fair Value Measurement*, includes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in an active market for identical assets or liabilities and the lowest priority to unobservable inputs. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The three levels of fair value hierarchy defined by GASB are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The District's investments in cash and cash equivalents are included as Level 1 assets.

Level 2 – Pricing inputs are other than quoted market prices in the active markets included in Level 1, which are either directly or indirectly observable for the asset or liability as of the reporting date. Level 2 inputs include the following:

- quoted prices for similar assets or liabilities in active markets;
- quoted prices for identical assets or liabilities in inactive markets;
- inputs other than quoted prices that are observable for the asset or liability; or
- inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 2 assets primarily include U.S. Treasury and government agency securities held in the Revenue funds and other Special Purpose Funds and U.S. Treasury and government agency securities, corporate bonds, and municipal bonds held in the Decommissioning funds.

Level 3 – Pricing inputs include significant inputs that are unobservable and cannot be corroborated by market data. Level 3 assets and liabilities are valued based on internally developed models and assumptions or methodologies using significant unobservable inputs. The District currently does not have any Level 3 assets or liabilities.

The District performs an analysis annually to determine the appropriate hierarchy level classification of the assets and liabilities that are included within the scope of GASB Codification Section 3100. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. There were no liabilities within the scope of GASB Codification Section 3100 as of December 31, 2022 and 2021.

The following tables set forth the District's financial assets that are accounted for and reported at fair value on a recurring basis by level within the fair value hierarchy as of December 31 (in 000's):

	2022			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 599,737	$ -	$ 599,737
Cash and cash equivalents	129,236	-	-	129,236
Decommissioning funds:				
U.S. Treasury and government agency securities	-	406,674	-	406,674
Corporate bonds	-	177,409	-	177,409
Municipal bonds	-	10,106	-	10,106
Cash and cash equivalents	8,264	-	-	8,264
	$ 137,500	$1,193,926	$ -	$ 1,331,426

	2021			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 494,201	$ -	$ 494,201
Cash and cash equivalents	342,438	-	-	342,438
Decommissioning funds:				
U.S. Treasury and government agency securities	-	449,241	-	449,241
Corporate bonds	-	221,767	-	221,767
Municipal bonds	-	9,951	-	9,951
Cash and cash equivalents	13,328	-	-	13,328
	$ 355,766	$1,175,160	$ -	$ 1,530,926

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2022, was as follows (in 000's):

	December 31, 2021	Increases	Decreases	December 31, 2022
Nondepreciable utility plant:				
Land and improvements	$ 79,319	$ 814	$ -	$ 80,133
Construction in progress	243,245	98,658	(81,062)	260,841
Total nondepreciable utility plant	322,564	99,472	(81,062)	340,974
Nuclear fuel*	105,507	70,411	(29,020)	146,898
Depreciable utility plant:				
Generation - Fossil	1,695,943	15,911	(2,949)	1,708,905
Generation - Nuclear	1,354,731	17,398	(2,895)	1,369,234
Transmission	1,426,109	23,634	(5,785)	1,443,958
Distribution	261,504	18,222	(12,047)	267,679
General	386,451	22,052	(23,015)	385,488
Total depreciable utility plant	5,124,738	97,217	(46,691)	5,175,264
Less reserve for depreciation	(3,034,216)	(115,315)	46,691	(3,102,840)
Depreciable utility plant, net	2,090,522	(18,098)	-	2,072,424
Utility plant activity, net	$ 2,518,593	$ 151,785	$ (110,082)	$ 2,560,296

* Nuclear fuel decreases represented amortization of $29.0 million.

Utility plant activity for the year ended December 31, 2021, was as follows (in 000's):

	December 31, 2020	Increases	Decreases	December 31, 2021
Nondepreciable utility plant:				
Land and improvements	$ 79,232	$ 87	$ -	$ 79,319
Construction in progress	230,751	103,643	(91,149)	243,245
Total nondepreciable utility plant	309,983	103,730	(91,149)	322,564
Nuclear fuel*	139,335	898	(34,726)	105,507
Depreciable utility plant:				
Generation - Fossil	1,678,206	29,697	(11,960)	1,695,943
Generation - Nuclear	1,347,068	9,346	(1,683)	1,354,731
Transmission	1,403,254	25,268	(2,413)	1,426,109
Distribution	262,996	20,729	(22,221)	261,504
General	381,917	7,994	(3,460)	386,451
Total depreciable utility plant	5,073,441	93,034	(41,737)	5,124,738
Less reserve for depreciation	(2,951,378)	(124,575)	41,737	(3,034,216)
Depreciable utility plant, net	2,122,063	(31,541)	-	2,090,522
Utility plant activity, net	$ 2,571,381	$ 73,087	$ (125,875)	$ 2,518,593

* Nuclear fuel decreases represented amortization of $34.7 million.

5. LONG-TERM CAPACITY CONTRACTS:

Long-term capacity contracts include the District's share of the construction costs of Omaha Public Power District's ("OPPD") 664-megawatt ("MW") Nebraska City Station Unit No. 2 ("NC2") coal-fired power plant. The District has a participation power agreement with OPPD for a 23.7% share of the power from this plant. NC2 began commercial operation on May 1, 2009, at which time the District began amortizing the amount of the capacity contract associated with the plant on a straight-line basis over the 40-year estimated useful life of the plant. Accumulated amortization was $62.1 million and $57.7 million as of December 31, 2022 and 2021, respectively. The unamortized amount of the plant capacity contract was $116.1 million and $120.7 million as of December 31, 2022 and 2021, respectively, of which $4.4 million was included in Prepayments and other current assets as of December 31, 2022 and 2021. The District's share of NC2 working capital was also included in Prepayments and other current assets and was $7.4 million and $7.3 million as of December 31, 2022 and 2021, respectively.

Long-term capacity contracts also include the District's purchase of the capacity of a 50-MW hydroelectric generating facility owned and operated by The Central Nebraska Public Power and Irrigation District ("Central"). The District and Central entered into a power purchase agreement which is to remain in effect until the hydro unit is retired and removed from commercial operation; however, the District has the right to terminate said Agreement upon notice and payment to Central of all of its costs attributable to the acquisition, construction, and operation of the hydro unit. The District is amortizing the contract on a straight-line basis over the 40-year estimated useful life of the facility. Accumulated amortization was $78.2 million and $75.8 million as of December 31, 2022 and 2021, respectively. The unamortized amount of the Central capacity contract was $8.5 million and $10.8 million as of December 31, 2022 and 2021, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2022 and 2021.

The District has an agreement whereby Central makes available all the production of the facility and the District pays all costs of operating and maintaining the facility plus a charge based on the amount of energy delivered to the District. Power purchased costs related to Central were $1.5 million and $1.8 million in 2022 and 2021, respectively.

6. INVESTMENT IN THE ENERGY AUTHORITY:

The District has an investment in The Energy Authority ("TEA"), a nonprofit corporation headquartered in Jacksonville, Florida, and incorporated in Georgia. TEA provides public power utilities access to dedicated resources and advanced technology systems. The District's interest in TEA is 17.65% as of December 31, 2022 and 2021. In addition to the District, the following utilities have interests of 17.65% each as of December 31, 2022: American Municipal Power, Inc.; JEA (Florida); Municipal Energy Authority of Georgia; and South Carolina Public Service Authority (a.k.a. Santee Cooper). The following utilities have interests in TEA of 5.875% each as of December 31, 2022: City Utilities of Springfield, Missouri and Gainesville Regional Utilities (Florida).

Such investment was $26.2 million and $21.8 million as of December 31, 2022 and 2021, respectively. TEA's revenues and costs are allocated to members pursuant to Settlement Procedures under the Operating Agreement. TEA is the District's market participant in SPP's Integrated Market and provides the District gas contract management and other services. The District accounts for its investment in TEA under the equity method of accounting.

As a member of TEA, the District made payment of a membership fee and certain contributions to capital and is providing certain guarantees for electric trading and other activities by TEA. Such guarantees have been authorized as Credit Obligations under the General Resolution on a parity with the General Revenue Bonds. The guarantees include $25.0 million to support business growth and trading due to TEA's California Community Aggregation program that provides for TEA or others to supply electricity to communities that were previously served by investor-owned utilities. The District was obligated to guaranty, directly or indirectly, a share of TEA's electric trading activities. The total amount guaranteed by the District for TEA's electric trading and other activities, including the California Community Aggregation Program, was up to $85.0 million, as of December 31, 2022, which any party claiming and prevailing under the guaranty might incur and be entitled to recover under its contract with TEA. Generally, the District's guaranty obligations for electric trading would arise if TEA did not make the contractually required payment for energy, capacity, or transmission which was delivered or made available or if TEA failed to deliver or provide energy, capacity, or transmission as required under a contract.

The District's exposure relating to TEA is limited to the District's investment in TEA, any accounts receivable from TEA, and trade guarantees provided to TEA by the District. Upon the District making any payments under its electric guaranty, it has certain contribution rights with the other members of TEA in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's interest in TEA and the guarantees they have provided. After such contributions have been made, the District would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the District has the right to reduce and/or terminate its guarantee obligations by providing advanced 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 District did not record any liabilities for these guarantees as of December 31, 2022 and 2021.

Financial statements for TEA may be obtained at The Energy Authority, 1301 Riverplace Blvd., Suite 2700, Jacksonville, Florida, 32207.

7. DEBT:

The following table summarizes debt balances as of December 31, 2022 and 2021, and debt activity for 2022 (in 000's):

	Total Debt at December 31, 2021	Increases	Decreases	Total Debt at December 31, 2022	Long-Term Debt at December 31, 2022	Current Liabilities at December 31, 2022
Revenue bonds	$ 1,186,876	$ -	$ (116,234)	$ 1,070,642	$ 965,517	$ 105,125
Revolving credit agreements	159,793	55,068	(66,129)	148,732	148,732	-
Total debt activity	$ 1,346,669	$ 55,068	$ (182,363)	$ 1,219,374	$ 1,114,249	$ 105,125

The following table summarizes debt balances as of December 31, 2021 and 2020, and debt activity for 2021 (in 000's):

	Total Debt at December 31, 2020	Increases	Decreases	Total Debt at December 31, 2021	Long-Term Debt at December 31, 2021	Current Liabilities at December 31, 2021
Revenue bonds	$ 1,402,629	$ 318,623	$ (534,376)	$ 1,186,876	$ 1,123,341	$ 63,535
Revolving credit agreements	135,918	131,556	(107,681)	159,793	159,793	-
Total debt activity	$ 1,538,547	$ 450,179	$ (642,057)	$ 1,346,669	$ 1,283,134	$ 63,535

General Revenue Bonds

On December 29, 2022, the District legally defeased $31.6 million of General Revenue Bonds, 2012 Series B, which were redeemed on January 1, 2023.

In October 2021, the District issued $106.4 million of General Revenue Bonds, 2021 Series C at a premium of $19.2 million and $30.8 million of General Revenue Bonds, 2021 Series D at a premium of $4.4 million for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2012 Series A, 2013 Series A, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $137.2 million of the proceeds from the General Revenue Bonds 2021 Series C and D, a $95.0 million draw from the TERCA and $7.6 million of other available funds. As a result, total debt service payments over the life of the bonds are expected to be reduced by $108.8 million, which will result in total present value savings of $97.9 million.

In March 2021, the District initiated the preliminary closing on $75.5 million of General Revenue Bonds, 2021 Series A (Forward Delivery) at a premium of $17.3 million, and $52.1 million of General Revenue Bonds, 2021 Series B (Forward Delivery) at a premium of $12.9 million, for the principal purpose of refunding certain of the District's outstanding General Revenue Bonds, 2014 Series A, 2014 Series C, and 2015 Series A-2. The refunding was completed with $157.8 million of the proceeds from the General Revenue Bonds, 2021 Series A and B, and $1.1 million of other available funds. As a result, total debt service payments over the life of the bonds are expected to be reduced by $42.6 million, which will result in total present value savings of $31.0 million. The 2021 Series A and B Forward Delivery transaction settled in October 2021.

The District expects to continue to finance from indebtedness a prior year SPP Notification to Construct capital project for approximately 226 miles of 345 kV transmission line (the "R-Project") which has an SPP approved estimated cost of $462.7 million. If the updated District cost estimate exceeds the SPP escalated baseline by more than 20%, the District would need to seek approval from SPP. The District previously issued General Revenue Bonds, 2020 Series A to finance a portion of the cost of the R-Project. The District has spent approximately $147.0 million through December 31, 2022, for design, construction mobilization and easement acquisitions. Additional information on the R-Project is in the Notes to Financial Statements, specifically Note 12.D., *SPP Membership and Transmission Agreements,* and Note 12.F., *Environmental, Endangered Species Act*.

Congressional action reduced the 35.0% interest subsidy, pursuant to the requirements of the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, on the District's 2010 Series A (Taxable Build America Bonds). Reductions were 5.7% for fiscal years ended September 30, 2022 and 2021, respectively.

There were outstanding principal amounts aggregating $3.9 million from legal defeasances of General Revenue Bonds, 2017 Series A, and $503.2 million from legal defeasances of General Revenue Bonds, 2012 Series A, 2013 Series A, 2014 Series A, 2014 Series C and 2015 Series A-2, as of December 31, 2022 and 2021, respectively.

The General Revenue Bonds are special obligations of the District payable solely by the Pledged Property, which is the revenues and all funds and accounts created under the General Resolution. The General Resolution defines Events of Default which may result in the declaration of the principal of all outstanding General Revenue Bonds and the accrued interest to be due and payable immediately. Events of Default include failure to make timely debt service payments, extended defaults in the performance of any debt covenants, and court order relating to bankruptcy or insolvency of the District.

Debt service payments and principal payments of the General Revenue Bonds as of December 31, 2022, are as follows (in 000's):

Year	Debt Service Payments	Principal Payments
2023	$ 149,913	$ 105,125
2024	109,982	69,770
2025	119,930	82,690
2026	101,156	67,475
2027	98,719	67,955
2028-2032	369,210	254,600
2033-2037	251,969	191,075
2038-2042	127,999	103,730
2043-2047	44,054	37,425
2048-2050	15,104	13,985
Total Payments	$ 1,388,037	$ 993,830

The fair value of outstanding General Revenue Bonds was determined using currently published rates. The fair value was estimated to be $1,018.9 million and $1,242.9 million as of December 31, 2022 and 2021, respectively.

<u>Tax-Exempt Revolving Credit Agreement</u>

The District entered into a TERCA with a commercial bank to provide for loan commitments to the District up to an aggregate amount not to exceed $150.0 million. The District had an outstanding balance under the TERCA of $47.9 million and $63.8 million as of December 31, 2022 and 2021, respectively. As such, the remaining credit available under TERCA was $102.1 million and $86.2 million as of December 31, 2022 and 2021, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates and the issuance of General Revenue Bonds. The carrying value approximates market value. The agreement was amended and renewed on September 15, 2022, with a termination date of September 12, 2025.

The obligation of the District to pay the principal, interest, bank fees, and expenses pursuant to the TERCA during the revolving credit period is payable from the Pledged Property subject and subordinated to the pledge of the Pledged Property to the payment of the General Revenue Bonds. However, if the TERCA is converted to a term loan, the payment obligation of the District under the TERCA would be on a parity with the District's obligation to pay the General Revenue Bonds.

The TERCA defines Events of Default which may result in the declaration of the principal and the accrued interest to be due and payable at an earlier date or immediately. Events of Default include failure to make timely debt service payments, extended defaults in the performance of any debt covenants, court order relating to bankruptcy or insolvency of the District, extended failure to pay a final unappealable judgment of $5.0 million or greater, an imposed debt moratorium or comparable restriction on debt service payments, and an extended long-term rating downgrade to below "BBB-" for credit-related reasons.

Taxable Revolving Credit Agreement

The District entered into a TRCA with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $200.0 million. The TRCA allows the District to increase the loan commitments to $300.0 million. The District had outstanding balances under the TRCA of $100.8 million and $95.9 million, as of December 31, 2022 and 2021, respectively. As such, the remaining credit available under TRCA, using the allowance to increase the loan commitments to $300.0 million, was $199.2 million and $204.1 million as of December 31, 2022 and 2021, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates and the issuance of revenue bonds. The carrying value approximates market value. The agreement was renewed on July 29, 2021, with a termination date of July 26, 2024.

The obligation of the District to pay the principal, interest, bank fees, and expenses pursuant to the TRCA during the revolving credit period is payable from the Pledged Property subject and subordinated to the pledge of the Pledged Property to the payment of the General Revenue Bonds. However, if the TRCA is converted to a term loan, the payment obligation of the District under the TRCA would be on a parity with the District's obligation to pay the General Revenue Bonds.

The TRCA defines Events of Default which may result in the declaration of the principal and the accrued interest to be due and payable immediately and the termination of the Agreement. Events of Default include failure to make timely debt service payments, extended defaults in the performance of any debt covenants, court order relating to bankruptcy or insolvency of the District, extended failure to pay a final unappealable judgment, an imposed debt moratorium or comparable restriction on debt service payments, and an extended long-term rating downgrade to below "BBB-".

General Revenue Bonds consist of the following (in 000's except interest rates):

December 31,	Interest Rate	2022	2021
General Revenue Bonds:			
2010 Series A Taxable Build America Bonds:			
Serial Bonds: 2022–2024	4.53% - 4.73%	$ 11,225	$ 16,595
Term Bonds: 2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2012 Series B:			
Serial Bonds: 2022–2032	2.875% - 5.00%	5,405	45,505
Term Bonds: 2033–2036	3.625%	2,320	2,320
2037–2042	3.625%	4,155	4,155
2015 Series A-1 Serial Bonds 2022–2034	3.00% - 5.00%	116,780	119,400
2016 Series A:			
Serial Bonds: 2024–2035	3.125% - 5.00%	53,665	53,665
Term Bonds: 2036–2040	5.00%	5,595	5,595
2016 Series B:			
Serial Bonds: 2028–2036	5.00%	64,570	64,570
Term Bonds: 2037–2039	5.00%	1,165	1,165
2016 Series C Serial Bonds 2022–2035	5.00%	46,455	50,945
2016 Series D:			
Serial Bonds: 2022–2035	3.00% - 5.00%	16,580	17,510
Term Bonds: 2036–2040	5.00%	9,505	9,505
2041–2045	5.00%	12,140	12,140
2016 Series E Taxable Serial Bonds 2022–2033	2.337% - 3.567%	52,060	56,050
2017 Series A Serial Bonds 2022–2027	3.00% - 5.00%	2,335	2,870
2017 Series B Serial Bonds 2022–2027	5.00%	28,660	33,605
2019 Series A Serial Bonds 2021–2034	5.00%	29,590	31,400
2019 Series B-1 Taxable Serial Bonds 2022–2028	2.166% - 2.593%	72,325	73,215
2019 Series B-2 Taxable Serial Bonds 2022–2028	2.166% - 2.593%	15,810	16,015
2020 Series A Serial Bonds 2024–2050	0.60%	125,825	125,825
2021 Series A Serial Bonds 2022–2039	5.00%	68,140	75,525
2021 Series B Serial Bonds 2022–2040	5.00%	50,580	52,080
2021 Series C Serial Bonds 2022–2031	5.00%	95,495	106,350
2021 Series D:			
Serial Bonds: 2022–2026	5.00%	2,555	12,085
Term Bonds: 2041–2043	4.00%	18,720	18,720
Total par amount of General Revenue Bonds		993,830	1,088,985
Unamortized premium net of discount		76,812	97,891
		1,070,642	1,186,876
Less – current maturities of General Revenue Bonds		(105,125)	(63,535)
Long-term General Revenue Bonds		$ 965,517	$ 1,123,341

8. PAYMENTS IN LIEU OF TAXES:

The District is required to make payments in lieu of taxes, aggregating 5.0% of the gross revenue derived from electric retail sales within the city limits of incorporated cities and towns served directly by the District. Such payments totaled $10.2 million and $9.9 million for the years ended December 31, 2022 and 2021, respectively.

9. ASSET RETIREMENT OBLIGATIONS:

Measurement of ARO under GASB guidance is based on the best estimate in today's dollars, or the current value, of cash outlays expected to be incurred in the future. The GASB guidance requires the recognition of a corresponding deferred outflow of resources. The District uses regulatory accounting to align asset retirement costs with their related recognition in rates. The difference in the ARO amounts and the related deferred outflows represents the amounts collected in rates and interest income on decommissioning funds.

AROs as of December 31, are as follows (in 000’s):

Description	2022	2021
CNS license termination costs	$ 832,439	$ 782,000
GGS and Sheldon ash landfills	11,011	10,932
Ainsworth	7,369	6,923
Underground storage tanks	1,000	1,000
	$ 851,819	$ 800,855

The District is required by the Nuclear Regulatory Commission (“NRC”) to decommission Cooper Nuclear Station after cessation of plant operations, consistent with regulations in the U.S. Code of Federal Regulations. The Cooper Nuclear Station license termination costs were based on an external study for costs for three different scenarios: 1) immediate commencement of decommissioning after license termination in 2034; 2) delayed decommissioning for 46 years after license termination; and 3) safe storage for 60 years after license termination. The costs were based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements. An expert panel, consisting of District management representatives with considerable nuclear experience, assigned probabilities to these different scenarios. These weighted probabilities were used when calculating the ARO Rates in the consumer price index for all urban consumers (“CPI-U”) were used to adjust these obligations for inflation, as the costs in the study were in 2019 dollars. The inflation rates used were 6.45% and 7.04% for the years 2022 and 2021, respectively. The District has funds set aside for decommissioning of $602.5 million and $694.3 million as of December 31, 2022 and 2021, respectively. These funds exceeded the NRC’s required funding provisions for nuclear decommissioning.

The District is required by the Environmental Protection Agency (“EPA”) and the Nebraska Department of Environment & Energy (“NDEE”) to decommission the ash landfills at Gerald Gentleman Station and Sheldon Station, consistent with their regulations. As GASB guidance is unclear related to the accounting treatment for ash landfill AROs, guidance in GASB Codification Section A10, *Certain Asset Retirement Obligations,* was considered analogous authoritative literature and applied in this situation. The ash landfills have an estimated closure date in the years 2086 and 2034 for Gerald Gentleman Station and Sheldon Station, respectively. The AROs were based on external studies to estimate costs using one scenario after an assessment of the physical site. The closure and post-closure costs were based on the Closure Plan in the studies and included final cover placements and lined surface water control structures. The costs in the latest studies were in 2019 and 2017 dollars for Gerald Gentleman Station and Sheldon Station, respectively. The rate of 6.45% in the CPI-U was used to adjust for inflation in 2022. The inflation rate of 4.14% used to adjust the obligations for 2021 was provided by the NDEE. The District provides guarantees and financial assurance through correspondence and supporting information to NDEE annually. The District included in rates decommissioning costs for certain assets at Gerald Gentleman Station and Sheldon Station. The costs included in rates for the decommissioning of the ash landfills were $0.8 million and $0.9 million for 2022 and 2021, respectively. These rate collections reduced the related deferred outflow for the ash landfills.

The District is required by contracts with the landowners of the Ainsworth Wind Energy Facility site to restore the property, as nearly as possible, to the condition it was in prior to the District’s use of the easement. Ainsworth Wind Energy Facility has an estimated closure date of September 30, 2025. The 2022 and 2021 ARO was based on an external study completed in 2021 for costs using one scenario. There are no legally required funding and assurance provisions associated with this ARO. The costs included in rates for the decommissioning of Ainsworth Wind Energy Facility were $1.4 million and $0.2 million for 2022 and 2021, respectively. These rate collections reduced the related deferred outflow for Ainsworth Wind Energy Facility.

The District is required by the NDEE to decommission the underground storage tanks at various locations in the District’s service area, consistent with its regulations. The remaining lives of the storage tanks cannot be reasonably estimated. The AROs were based on the best estimate of District management representatives with expertise in environmental issues. The District provided guarantees and financial assurance through correspondence and supporting information to NDEE annually. There have not been any decommissioning costs for the underground storage tanks included in rates.

10. RETIREMENT PLAN:

The Nebraska Public Power District 401(k) Plan (the "Plan") was established and administered by the District to help supplement retirement income of participating regular full-time and part-time employees. There were 1,962 and 1,947 active Plan members as of December 31, 2022 and 2021, respectively. Plan provisions and contribution requirements are established and may be amended by the Board.

Plan members are eligible to begin participation in the Plan immediately upon hire. The Plan permits Pre-tax and Roth Elective deferral contributions. Contributions up to 5.0% of base pay are eligible for District matching dollars after six months of employment. The District contributes two times the Plan member's contribution based on eligible earnings up to $75,000. On eligible earnings greater than $75,000, the District contributes one times the Plan member's contribution. The Participants' contributions were $17.9 million and $17.2 million for 2022 and 2021, respectively. The District's matching contributions were $16.4 million and $16.0 million for 2022 and 2021, respectively. Total contributions of $1.7 million were accrued in accounts payable and accrued liabilities for both years as of December 31, 2022 and 2021.

Plan members are immediately vested in their own contributions and earnings and become vested in the District's contributions and earnings based on the following vesting schedule:

Years of Vesting Participation	Percent
5 years or more	100%
4 years	75%
3 years	50%
2 years	25%
Less than 2 years	0%

Nonvested District contributions are first used to cover Plan administrative expenses and any remaining forfeitures are allocated back to Plan participants.

Employees may also contribute to an eligible deferred compensation plan which is intended to meet the requirements of Code Section 457(b) ("457(b) Plan"). The 457(b) Plan is a defined contribution plan which permits Pre-tax and Roth elective deferral contributions. The Plan does not provide for a District match but does permit discretionary non-elective contributions by the District. There were 771 and 731 active Plan members as of December 31, 2022 and 2021, respectively. Participants may change their elective deferrals at any time. Early withdrawals can be made from the 457(b) Plan following separation of service regardless of age with no IRS penalty. Income taxes are owed on any withdrawals of pre-tax elective deferral contributions and discretionary non-elective contributions. Income taxes are not owed on withdraws of Roth elective deferral contributions if certain requirements are met. The total contributions to the 457(b) Plan were $2.7 million for both 2022 and 2021.

11. OTHER POSTEMPLOYMENT BENEFITS:

A. *General Information Regarding the OPEB Plan –*

Plan Description

The District's Postemployment Medical and Life Benefits Plan ("Plan") provides postemployment hospital-medical and life insurance benefits to qualifying retirees, surviving spouses, and employees in disability status and their eligible dependents. Benefits and related eligibility, funding and other Plan provisions, for this single-employer, defined benefit Plan, are authorized by the Board. The Plan is administered by the District.

The Plan has been amended over the years and provides different benefits based on hire date and/or the age of the employee. These benefits include a self-insured Pre-Medicare plan, fully-insured Medicare Supplement and Part D Plans, and a Retiree Reimbursement Account ("RRA"). The RRA was approved by the Board in January 2020 with an effective date of January 1, 2021. The addition of the RRA expanded the availability of benefits to post-age 65 retirees hired from January 1, 1999 through December 31, 2003, and retirees hired on or after January 1, 2004. The RRA provides reimbursements for applicable healthcare premiums up to an annual amount for 2022 of $4,120 and $2,060 for pre-age 65 and post-age 65 retirees, respectively. The Board authorized an increase in these annual amounts to $4,244 and $2,122 for 2023. The District also provides a postemployment death benefit for $5,000 for qualifying employees.

Employees Covered by Benefit Terms

Hired Prior to January 1, 1993	District and retiree share in premium costs for retiree and dependents prior to age 60; District pays 100% of premiums at age 60 and after
Hired January 1, 1993 to December 31, 1998	District and retiree share in premium costs for retiree and dependents until age 65; District share of premiums capped at age 65
Hired January 1, 1999 to December 31, 2003	District and retiree share in premium costs for retiree and dependents until age 65; For employees active as of January 1, 2020, retiree eligible for RRA at age 65 and after
Hired January 1, 2004 and after	For employees active as of January 1, 2020, retiree eligible for RRA

Employees Covered by Benefit Terms
The following table shows the employees covered by the hospital-medical benefit terms as of January 1:

	2022	2021
Active employees	1,914	1,893
Inactive employees in retirement status	1,455	1,419
Inactive employees in long-term disability status	42	49
Total employees covered by benefit terms	3,411	3,361

The following table shows the employees covered by the life insurance benefit terms as of January 1:

	2022	2021
Active employees	1,914	1,893
Inactive employees in retirement status	1,312	1,279
Inactive employees in long-term disability status	46	53
Total employees covered by benefit terms	3,272	3,225

Contributions
The Board annually approves the funding for the Plan, which has a minimum funding requirement of the actuarially-determined annual required contribution to achieve full funding status on or before December 31, 2033. The District OPEB contributions were $6.3 million and $28.3 million for 2022 and 2021, respectively.

Contributions from Plan members are the required premium share for inactive members, which is based on hire date and/or age. Contributions from Plan members were $0.6 million for 2022 and 2021. As these contributions were from inactive members, they were reported as a reduction of benefit expenses. Members do not contribute to the cost of the life insurance benefits.

B. *Net OPEB (Asset) Liability –*
The District's net OPEB asset was measured as of January 1, 2022, and January 1, 2021. For each of these measurement dates, the total OPEB liability was used to calculate the net OPEB asset/liability and was determined by an actuarial valuation as of these dates.

Actuarial Assumptions and Methods

The actuarial assumptions and methods used in the January 1, 2022 and 2021, respectively actuarial valuation were based on the results of an actuarial experience study completed during 2018. The total OPEB liability in the January 1, 2022 and 2021, respectively, actuarial valuation was determined using the following actuarial assumptions and methods, applied to all periods included in the measurement, unless otherwise specified:

Actuarial cost method	Entry Age Normal
Healthcare cost trend rates	Pre-Medicare: 6.4% initial for 2022, ultimate 4.5% Post-Medicare: 6.7% initial for 2022, ultimate 4.5% Pre-Medicare: 6.7% initial for 2021, ultimate 4.5% Post-Medicare: 7.1% initial for 2021, ultimate 4.5%
RRA increase rate	3.0%
Administrative cost trend	3.0%
Inflation	2.2% for 2022 and 2.1% for 2021
Salary increases	4.0%
Investment rate of return	5.75% for 2022 and 6.0% for 2021, net of investment expense, including inflation
Discount rate	5.75% for 2022 and 6.0% for 2021, based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	Pub-2010 "General" table with generational projection using Scale MP-2021 for 2022 Pub-2010 "General" table with generational projection using Scale MP-2020 for 2021
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 60% of females are assumed to have spouses who will elect coverage. Males are assumed to be two years older than their spouses. Females are assumed to be two years younger.
Participation rate	95.0%

The long-term expected rate of return on OPEB Plan investments was determined using a building-block method in which best-estimate ranges of expected future rates of return (expected returns, net of OPEB Plan investment expense and inflation) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The target allocation and best estimates of geometric real rates of return for each major asset class are summarized in the following table for the valuation measurement date of January 1:

		Long-Term Expected Real Rate of Return	
Asset Class	Target Allocation	2022	2021
Equity and Real Estate	70%	6.6%	6.9%
Fixed income	30%	2.6%	2.0%
	100%	5.6%	5.7%

Discount Rate

The discount rate used to measure the total OPEB liability was 5.75% and 6.0% for the actuarial valuations as of January 1, 2022 and 2021, respectively. The projection of cash flows used to determine the discount rate assumed that contributions will be made at rates equal to the actuarially determined contribution rates. Based on those assumptions, the Plan's fiduciary net position was projected to be available to make all projected benefit payments for current active and inactive employees. Therefore, the long-term expected rate of return on Plan investments was applied to all periods of projected benefit payments to determine the total OPEB liability.

C. Changes in the Net OPEB (Asset) Liability –

The following table shows the total OPEB liability, plan fiduciary net position and net OPEB asset as of January 1, 2022, and the changes during this period, based on the valuation measurement date of January 1, 2022 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB (Asset) Liability (a-b)
Balances at January 1, 2021	$ 309,022	$ 343,549	$ (34,527)
Changes for the year:			
Service cost	2,663	-	2,663
Interest	18,237	-	18,237
Changes of benefit terms	-	-	-
Differences between expected and actual experience	(7,054)	-	(7,054)
Changes of assumptions	12,620	-	12,620
Contributions - employer	-	28,283	(28,283)
Net investment income	-	46,479	(46,479)
Benefit payments	(15,710)	(15,710)	-
Administrative expense	-	(259)	259
Net changes	10,756	58,793	(48,037)
Balances at January 1, 2022	$ 319,778	$ 402,342	$ (82,564)

There were changes made in certain assumptions for the valuation measurement date of January 1, 2022. The mortality assumptions were updated to the Pub-2010 "General" table with generational projection using Scale MP- 2021. The healthcare trend rates were also updated.

Sensitivity of the Net OPEB (Asset) Liability to Changes in the Discount Rate

The following table shows the net OPEB asset of the District, as well as what the net OPEB asset would be if it were calculated using a discount rate that is 1-percentage-point lower (4.75%) or 1-percentage-point higher (6.75%) than the discount rate (5.75%) at the measurement date of January 1, 2022 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset) Liability	$ (43,053)	$ (82,564)	$ (115,637)

Sensitivity of the Net OPEB (Asset) Liability to Changes in the Healthcare Cost Trend Rates

The following table shows the net OPEB asset of the District, as well as what the net OPEB asset would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 5.4% initial to 3.5% ultimate, Post-Medicare ranging from 5.7% initial to 3.5% ultimate) or 1- percentage-point higher (Pre-Medicare ranging from 7.4% initial to 5.5% ultimate, Post-Medicare ranging from 7.7% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 6.4% initial to 4.5% ultimate, Post-Medicare ranging from 6.7% initial to 4.5% ultimate) at the measurement date of January 1, 2022 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB (Asset) Liability	$ (114,260)	$ (82,564)	$ (44,815)

The following table shows the total OPEB liability, plan fiduciary net position and net OPEB asset as of January 1, 2021, and the changes during this period, based on the valuation measurement date of January 1, 2021 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB Liability (a-b)
Balances at January 1, 2020	$ 305,200	$ 282,260	$ 22,940
Changes for the year:			
Service cost	2,103	-	2,103
Interest	18,775	-	18,775
Changes of benefit terms	8,598	-	8,598
Differences between expected and actual experience	(20,995)	-	(20,995)
Changes of assumptions	9,367	-	9,367
Contributions - employer	-	28,283	(28,283)
Net investment income	-	47,237	(47,237)
Benefit payments	(14,026)	(14,026)	-
Administrative expense	-	(205)	205
Net changes	3,822	61,289	(57,467)
Balances at January 1, 2021	$ 309,022	$ 343,549	$ (34,527)

There were changes made in certain assumptions for the valuation measurement date of January 1, 2021. The mortality assumptions were updated to the Pub-2010 "General" table with generational projection using Scale MP- 2020. The healthcare trend rates were also updated. The changes in benefit terms for 2021 were for the addition of the RRA.

<u>Sensitivity of the Net OPEB (Asset) Liability to Changes in the Discount Rate</u>
The following table shows the net OPEB asset of the District, as well as what the net OPEB asset would be if it were calculated using a discount rate that is 1-percentage-point lower (5.0%) or 1-percentage-point higher (7.0%) than the discount rate (6.0%) at the measurement date of January 1, 2021 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB (Asset) Liability	$ 3,411	$ (34,527)	$ (66,309)

<u>Sensitivity of the Net OPEB (Asset) Liability to Changes in the Healthcare Cost Trend Rates</u>
The following table shows the net OPEB asset of the District, as well as what the net OPEB asset would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 5.7% initial to 3.5% ultimate, Post-Medicare ranging from 6.1% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 7.7% initial to 5.5% ultimate, Post-Medicare ranging from 8.1% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 6.7% initial to 4.5% ultimate, Post-Medicare ranging from 7.1% initial to 4.5% ultimate) at the measurement date of January 1, 2021 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB (Asset) Liability	$ (65,166)	$ (34,527)	$ 1,981

<u>OPEB Plan Fiduciary Net Position</u>
Detailed information about the OPEB Plan Fiduciary Net Position is available in separately issued audited financial statements for Nebraska Public Power District Postemployment Medical and Life Benefits Plan available on the District's website, NPPD.com.

D. OPEB Expense, Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB –
The Board annually approves the OPEB expense in rates and has authorized the use of regulatory accounting to equate OPEB expense with the amount in rates. OPEB expense was negative $24.8 million for 2022, as calculated under GASB Codification Section P50, *Postemployment Benefits Other Than Pensions-Reporting for Benefits Provided through Trusts that Meet Specified Criteria-Defined Benefit,* which was largely due to the expected investments returns and amortization exceeding the service and interest costs. With regulatory accounting, OPEB expense and the amount included in rates was $6.3 million for 2022.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2022 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ -	$ 43,780
Changes in assumptions	17,377	1,230
Difference between actual and expected earnings	3,744	48,954
Contributions made during the year ended December 31, 2022	6,294	-
	$ 27,415	$ 93,964

The deferred outflows of resources related to the contributions made during the year ended December 31, 2022 will be recognized in the actuarial valuation with a measurement date of January 1, 2023. The net of the other deferred outflows and deferred inflows of resources will be recognized as a reduction in OPEB expense as follows (in 000's):

Year	Amount
2023	$ (22,609)
2024	(25,086)
2025	(16,464)
2026	(8,790)
2027	(549)
2028	655
Total	$ (72,843)

OPEB expense was negative $8.4 million for 2021, as calculated under the GASB guidance, which is largely due to the expected investments returns and amortization exceeding the service and interest costs. With regulatory accounting, OPEB expense and the amount included in rates was $28.3 million for 2021. The regulatory accounting OPEB expense is higher because it includes the amortization of costs related to prior periods.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2021 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 74	$ 49,489
Changes in assumptions	7,990	1,571
Difference between actual and expected earnings	7,487	42,421
Contributions made during the year ended December 31, 2021	28,283	-
	$ 43,834	$ 93,481

The deferred outflows of resources related to the contributions made during the year ended December 31, 2021 were recognized in the actuarial valuation with a measurement date of January 1, 2022. The net of the other deferred outflows and deferred inflows of resources will be recognized as a reduction in OPEB expense as follows (in 000's):

Year	Amount
2022	$ (20,678)
2023	(18,343)
2024	(20,820)
2025	(12,198)
2026	(4,523)
2027	(1,368)
Total	$ (77,930)

Additional information is available in the unaudited Required Supplementary Information section following the Notes to Financial Statements.

12. COMMITMENTS AND CONTINGENCIES:

A. *Fuel Commitments –*
The District has various coal supply contracts with minimum estimated future payments of $156.0 million at December 31, 2022. These contracts expire at various times through the end of 2027. The coal transportation contract in place is sufficient to deliver coal to the generation facilities through and beyond the expiration date of the aforementioned contracts and is subject to price escalation adjustments.

The District has a contract for conversion services of uranium-to-uranium hexafluoride which is in effect through 2026, a contract for all requirements for enrichment services, a contract for all requirements for fabrication services through the final reload before the end of the current operating license of Cooper Nuclear Station which is January 18, 2034, and a spot uranium contract scheduled for delivery in October of 2023. These commitments for nuclear fuel material and services have combined estimated future payments of $197.0 million, if needed.

B. *Power Purchase and Sales Agreements –*
The District has entered into a participation power agreement (the "NC2 Agreement") with OPPD to purchase 23.7% of the power of NC2, estimated to be 157 MW of the power from the 664-MW coal-fired power plant constructed by OPPD. The initial term of the agreement is for 40 years following the Commercial Operation date, which was in May 2009.The NC2 Agreement contains a step-up provision obligating the District to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs, and reserves related to NC2 in the event of a defaulting power purchaser. The District's obligation pursuant to such step-up provision is limited to 160.0% of its original participation share (23.67 percent). No such default has occurred to date.

The District has entered into a participation power sales agreement with Municipal Energy Agency of Nebraska ("MEAN") for the sale to MEAN of the power and energy from Gerald Gentleman Station and Cooper Nuclear Station of 50 MW which began January 1, 2011 and continues through December 31, 2023.

The District has entered into power sales agreements with Lincoln for the sale to Lincoln of 8.0% of the net power and energy of Gerald Gentleman Station. In return, Lincoln agrees to pay 8.0% of all costs (excluding fuel costs) attributable to Gerald Gentleman Station. This agreement is to terminate upon the later of the last maturity of the debt attributable to Gerald Gentleman Station or the date on which the District retires such station from commercial operation.

The District has wholesale power purchase commitments with Western which consist of 148.5 MW of firm power and 287 MW of firm peaking power from the Upper Great Plains Region through 2050, and approximately 4 MW of firm power from the Rocky Mountain Region through 2054. The District also receives and pays for approximately 4 MW of firm power from the Upper Great Plains Region for pass through to four Native American tribes through 2050. The annual minimum payments of these wholesale purchase commitments were $26.9 million for 2022. Western announced a rate increase, which would be effective January 1, 2023, subject to future rate hearings. The annual minimum future payments with the rate increase are approximately $32.2 million.

The District owns and operates the 60-MW Ainsworth Wind Energy Facility and has 20-year participation power agreements to sell 18 MW to three other utilities which terminate on September 30, 2025. In addition, the District has power purchase agreements with seven wind facilities having a total capacity of 435 MW. These agreements are for terms ranging from 20 to 25 years and require the District to purchase all the electric power output of these wind facilities. The District has entered into power sales agreements to sell 154 MW of this capacity to four other utilities in Nebraska over similar terms.

The District has entered into a power purchase agreement with Central for the purchase of the net power and energy produced by the Kingsley Project during its operating life. The Kingsley Project is a hydroelectric generating unit at the Kingsley Dam in Keith County, Nebraska with a summer 2022 accredited net capacity of 41.7 MW. The District and Central entered into a power purchase agreement which is to remain in effect until the hydro unit is retired and removed from commercial operation; however, the District has the right to terminate said Agreement upon notice and payment to Central of all of its costs attributable to the acquisition, construction, and operation of the hydro unit.

C. *Retail Agreements and Wholesale Power Contracts* –

Retail Agreements

The District entered into long-term PRO Agreements with 79 municipalities for the operation of certain retail electric distribution systems. Seventy-seven of these municipalities have renewed or enhanced their PRO Agreements with terms of 20 or 25 years expiring between 2037 and 2045. These 77 retail PRO Agreement customers represented 73.6% of retail revenues for 2022. The remaining two PRO Agreements are being actively worked for renewal and expire in 2029 and 2030. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal property additions during the term of the agreement.

Wholesale Power Contracts

The District serves its wholesale customers under total and partial requirements contracts that require them to purchase total power and energy requirements from the District, subject to certain exceptions. In 2016, the District entered into 20-year Wholesale Power Contracts ("2016 Contracts") with 22 public power districts, one cooperative, and 38 municipalities. One public power district and 9 municipalities were served under the 2002 Contracts ("2002 Contracts"), which expired on December 31, 2021.

The 2016 Contracts allow a wholesale customer to give notice to reduce its purchase of demand and energy requirements from the District based on a comparison of the District's average annual wholesale power costs in a given year compared to power costs of U.S. utilities for such year listed in the National Rural Utilities Cooperative Finance Corporation Key Ratio Trend Analysis (Ratio 88) (the "CFC Data"). The CFC Data places a utility's power costs in percentiles so that any given utility can compare its power costs on a percentile basis to the CFC published quartile information. The 2016 Contracts allow a wholesale customer to reduce its demand and energy purchases from the District if the District's average annual wholesale power costs percentile level for a given year is higher than the 45th percentile level (the "Performance Standard Percentile") of the power costs of U.S. utilities for such year as listed in the CFC Data. The 2016 Contracts would not allow any reductions in demand and energy purchases by a wholesale customer as long as the District's average annual wholesale power costs percentile remains below the Performance Standard Percentile.

The following table lists the District's wholesale power costs percentile for the calendar years 2017 to 2021 set forth in the CFC Data:

CFC Data	
Year	Percentile
2017	26.0%
2018	26.9%
2019	29.5%
2020	23.2%
2021	12.4%

There were ten wholesale customers on the 2002 Contracts which expired on December 31, 2021. In 2021, these customers purchased at least 10% of their demand and energy from the District.

D. *SPP Membership and Transmission Agreements* –

The District is a member of SPP, a regional transmission organization based in Little Rock, Arkansas. Membership in SPP provides the District reliability coordination service, generation reserve sharing, regional tariff administration, including generation interconnection service, network, and point-to-point transmission service, and regional transmission expansion planning. On March 1, 2014, SPP commenced a Day-Ahead, Ancillary Services, and Real-Time Balancing Market Integrated Market. The Integrated Market also provides a financial market to hedge unplanned transmission congestion, or financial virtual products to hedge uncertainties, such as unplanned outages.

The District has received an SPP Notification to Construct for the R-Project, which allows the cost of construction to be included in SPP annual revenue requirements. The R-Project consists of the construction of approximately 226 miles of 345 kV transmission line from Gerald Gentleman Station, north to a substation east of Thedford, then eastward to a new substation in Holt County interconnected to an existing 345 kV line owned by Western. The R-Project will strengthen the reliability of the District's transmission system, reduce transmission congestion, and allow for the integration of future renewable generation in an area of the state that lacks sufficient transmission access. The R-Project construction is currently delayed because of litigation which is discussed further in this Note in section 12.F., *Environmental, Endangered Species Act*.

The District, as the owner of the R-Project, had previously entered into a generator interconnection agreement with SPP and Thunderhead Wind Energy LLC (“Thunderhead”), that would allow the proposed Thunderhead Wind Energy Center to interconnect at the Holt County substation, which is to be constructed and owned by the District, and is in the eastern terminus of the R-Project. In 2021, FERC approved a revised generator interconnection agreement and settlement agreement that changed the scope of the generator interconnection agreement to include construction of the majority of the Holt County substation. This change transfers an estimated $11.0 million in construction costs from the R-Project to the generator interconnection agreement and, upon completion, would allow limited operation of the Thunderhead Wind Energy Center. If the R-Project fails to obtain the required permitting and regulatory approvals and the District decides to terminate the R-Project, the District would request SPP to withdraw its Notification to Construct the R-Project. If the SPP Board approves said notice to withdraw, the District would be required to provide SPP information relating to the costs incurred for the R-Project.

The estimated cost approved by SPP for the R-Project is $462.7 million. If the updated District cost estimate exceeds the SPP escalated baseline by more than 20%, the District would need to seek approval from SPP. The District awarded a contract for the construction of the R-Project in January 2019. The District has spent approximately $147.0 million through December 31, 2022, for design, construction mobilization, purchase of lattice tower steel, and easement acquisitions.

E. *Cooper Nuclear Station –*
On November 29, 2010, the NRC formally issued a certificate to the District to commemorate the renewal of the operating license for Cooper Nuclear Station for an additional 20 years until January 18, 2034. Cooper Nuclear Station entered the 20-year period of extended operation on January 18, 2014.

In October 2003, the District entered into an agreement for support services at Cooper Nuclear Station with Entergy, a wholly owned indirect subsidiary of Entergy Corporation. In 2010, the Entergy Agreement was amended and extended by the parties until January 18, 2029, subject to either party’s right to terminate without cause by providing notice and paying a $20.0 million termination charge. Subsequently, the parties amended the agreement in 2017 restricting the ability to terminate without cause for a five-year period ending December 2022. In exchange for the limitation to terminate without cause, the management fee schedule was decreased by 18.0% during the five-year period. The Entergy Agreement required the District to reimburse Entergy’s cost of providing services, and to pay Entergy annual management fees. These annual management fees were $16.2 million for 2021. On July 31, 2022 the District and Entergy mutually agreed to terminate the Entergy agreement without cause resulting in no termination fees.

Cooper Nuclear Station substantially completed the construction of a dry cask used fuel storage project in December 2009 to support plant operations until 2034, which is the end of the operating license. The first loading campaign was completed in January 2011 and encompassed the loading of 488 used fuel assemblies from the Cooper Nuclear Station used fuel pool into eight dry used fuel storage casks for on-site storage. A second loading campaign, encompassing the loading of 610 used fuel assemblies into ten dry used fuel storage casks, began in April 2014 and was completed in June 2014. The third loading campaign, encompassing the loading of 732 used fuel assemblies into 12 dry used fuel storage casks, began in June 2017 and was completed in November 2017. The fourth loading campaign is expected in 2025.

As part of various disputed matters between GE and the District, GE has agreed to continue to store at the Morris Facility the spent nuclear fuel assemblies from the first two full core loadings at Cooper Nuclear Station at no additional cost to the District until the expiration of the current NRC license in May 2042 for the Morris Facility. After that date, storage would continue to be at no cost to the District as long as GE can maintain the NRC license for the Morris Facility on essentially the existing design and operating configuration.

As a result of the failure of the DOE to dispose of spent nuclear fuel from Cooper Nuclear Station as required by contract, the District commenced legal action against the DOE on March 2, 2001. The initial settlement agreement addressed future claims through 2013. On January 13, 2014, the District and the DOE agreed to extend the settlement agreement through 2016. On March 2, 2017, the District and the DOE agreed to extend the settlement agreement through 2019. Settlements from the DOE for damages totaled $139.9 million for the years 2009 through 2022. The District accepted the DOE’s offer of $6.7 million for the 2019 claim, and the funds were received in October 2020. In September 2020, the District and the DOE agreed to an additional three-year extension of the settlement or years 2020 through 2022. The District and the DOE are currently negotiating a three-year extension. The District also reserves the right to pursue future damages through the contract claims process. A corresponding regulatory liability for these DOE receipts was established in Other deferred inflows of resources. The District plans to use the funds to pay for costs related to Cooper Nuclear Station. The balance in the regulatory liability was $78.3 million as of December 31, 2022 and 2021.

Under the terms of the DOE contracts, the District was also subject to a one mill per kilowatt-hour ("kWh") fee on all energy generated and sold by Cooper Nuclear Station, which was paid on a quarterly basis to DOE. The District includes a component in its wholesale and retail rates for the purpose of funding the costs associated with nuclear fuel disposal. While the District expects that the revenues developed therefrom will be sufficient to cover the District's responsibility for costs currently outlined in the Nuclear Waste Policy Act, the District can give no assurance that such revenues will be sufficient to cover all costs associated with the disposal of used nuclear fuel. On May 9, 2014, the DOE provided notice that they would adjust the spent fuel disposal fee to zero mills per kWh effective May 16, 2014. Correspondingly, no additional payments have been made to the DOE for fuel disposal since that date. The Board authorized the continued collection of this fee at the same rate. This approach ensures costs are recognized in the appropriate period with current customers receiving the benefits from Cooper Nuclear Station paying the appropriate costs. The expense for spent nuclear fuel disposal is recorded based on net electricity generated and sold and the regulatory liability will be eliminated when payments are made for spent nuclear fuel disposal.

Under the provisions of the Federal Price Anderson Act, the District and all other licensed nuclear power plant operators could each be assessed for claims in amounts up to $137.6 million per unit owned in the event of any nuclear incident involving any licensed facility in the nation, with a maximum assessment of $20.5 million per year per incident per unit owned.

The NRC evaluates nuclear plant performance as part of its reactor oversight process ("ROP"). The ROP monitors licensee performance in three broad strategic performance areas: reactor safety, radiation safety and safeguards. The process focuses on licensee performance within each of the seven cornerstones of safety included in the three strategic areas. Results from the monitor cornerstones are compiled and published in the NRC's ROP Action Matrix Summary. Best performing plants are included in the Licensee Response Column where routine inspector and staff interaction is the norm. As of December 31, 2022, Cooper Nuclear Station was in the Licensee Response Column, which is the first or best of the five NRC defined performance categories and has been in this column since the first quarter of 2012.

Refueling and maintenance outages are required to be performed at Cooper Nuclear Station approximately every two years. The most recent refueling and maintenance outage began on September 28, 2022 and was completed on November 12, 2022. During this outage, in addition to replacing 188 fuel assemblies and conducting routine maintenance and inspections, the emergency station startup transformer, main generator exciter and a reactor feed pump turbine were replaced. The next refueling and maintenance outage is currently planned for the fall of 2024.

Significant operations and maintenance expenses are incurred in an outage year. The Board has authorized the collection of these costs over a multi-year period to levelize revenue requirements for expenses and help ensure the customers receiving the benefits from Cooper Nuclear Station are paying the costs. The regulatory liability for the pre-collection of outage costs was eliminated through revenue recognition during the 2022 outage year and was $21.0 million as of December 31, 2021.

F. *Environmental* –

Water

The Federal Clean Water Act contains requirements with respect to effluent limitations relating to the discharge of any pollutant and to the environmental impact of cooling water intake structures. The NDEE establishes the requirements for the District's compliance with the Clean Water Act through issuance of National Pollutant Discharge Elimination System ("NPDES") permits. NDEE issued the District permits for the following facilities: Gerald Gentleman Station, Sheldon Station, Cooper Nuclear Station, Beatrice Power Station, Canaday Station and the North Platte Office Building. The NPDES permits for Cooper Nuclear Station and Gerald Gentleman Station require the installation of 316(b) environmental modifications. The initial designs and engineering plans for the modified traveling screens was approved by the NDEE for Cooper Nuclear Station, the installation of the screens must begin by October 1, 2024 and installed by July 1, 2025. The initial designs and engineering plans for the modified traveling screens for Gerald Gentleman Station are being finalized and will be submitted to the NDEE for review and approval by April 1, 2023. The current estimated costs for this technology at Cooper Nuclear Station and Gerald Gentleman Station are $7.8 million and $7.3 million, respectively.

On January 2, 2016, the final Steam Electric Power Plant Effluent Guidelines rule (the "Effluent Rule") became effective. The Effluent Rule revises the technology-based effluent limitation guidelines and standards that would strengthen the existing controls on discharges from steam electric power plants and sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. Generally, the Effluent Rule establishes new or additional requirements for wastewater streams from the following processes and byproducts associated with steam electric power generation: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke. While the District facilities subject to the Effluent Rule are Cooper Nuclear Station, Gerald Gentleman Station, Sheldon Station and Canaday Station, the Effluent Rule only has an impact on Sheldon Station. Sheldon Station will be required to comply with the Effluent Rule only for its bottom ash transport water. On August 31, 2020, the EPA Administrator signed the Steam Electric Reconsideration Rule, which modifies the existing Effluent Rule and allows for three separate compliance options. The District selected to install a high recycle system and submitted an initial certification statement on April 15, 2022. The deadline for completion of any construction upgrades to comply with the Effluent Rule is December 31, 2025.

<u>Acid Rain Program</u>

The Clean Air Act Amendments Title IV established a regulatory program, known as the Acid Rain Program, to address the effects of acid rain and impose restrictions on sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") emissions. Acid Rain Permits have been issued for the following facilities: Gerald Gentleman Station, Sheldon Station, Canaday Station and Beatrice Power Station. The Acid Rain Permits allow for the discharge of SO_2 at each facility pursuant to an allowance system. Based on current generation projections through 2028, the District expects to have sufficient Acid Rain allowances to cover affected facilities through 2028, but may be required to purchase additional allowances in the future.

<u>Mercury and Air Toxic Standards</u>

On February 16, 2012, the EPA issued a final rule intended to reduce emissions of toxic air pollutants from power plants. Specifically, the Mercury and Air Toxics Standards ("MATS") Rule requires reductions in emissions from new and existing coal- and oil-fired steam utility electric generating units of toxic air pollutants. The affected District facilities, which are Gerald Gentleman Station and Sheldon Station, are in compliance with the MATS Rule.

<u>Cross-State Air Pollution Rule</u>

The EPA issued a rule in 2012 which is referred to as the Cross-State Air Pollution Rule ("CSAPR") that would require significant reductions in SO_2 and NO_x emissions in a number of states, including Nebraska. CSAPR compliance periods went into effect on January 1, 2015. Based on the current CSAPR allocation methodology and current generation projections through 2028, the District expects to have sufficient CSAPR allowances to cover affected facilities emission requirements through 2028, but may be required to purchase additional allowances in the future.

<u>Regional Haze</u>

The EPA issued final regulations for a Regional Haze Program in June 1999 and updated those regulations in 2017. The purpose of the regulations is to improve visibility in the form of reducing regional haze in 156 national parks and wilderness areas across the country. Haze is formed, in part, from emissions of SO_2 and NO_x. The program is being implemented over 60 years in 10-year planning phases, with the goal of reaching "natural conditions" for visibility in all Class I areas by 2064. The District's Sheldon Station Unit No. 1 and Gerald Gentleman Station Units No. 1 and No. 2 were subject to the first phase of Regional Haze evaluation. Sheldon Station Unit No. 2 was not subject to the first phase evaluation due to its initial start-up date. Canaday Station and Beatrice Power Station will also not be affected in the first phase of the Regional Haze Program.

On June 5, 2020, the District received an Information Collection Request ("ICR") from the NDEE for information pertaining to the second planning phase (2018-2028). Based on modeling performed by Central States Air Resources Agencies, the NDEE determined that Gerald Gentleman Station may contribute to the visibility impairment at multiple Class I areas. The NDEE ICR requested information regarding the cost to install and operate four SO_2 control options at Gerald Gentleman Station Units No. 1 and No. 2. The District submitted the initial response to the NDEE ICR on November 2, 2020 and supplemental response on December 30, 2020. The District has provided information including detailed air modeling results.

In late 2022, the NDEE shared a draft State Implementation Plan ("SIP") with the federal land managers, who provided comments in January 2023. NDEE is considering these comments and continuing to move forward with finalizing a draft SIP that it will release for public notice and comment in the coming months.

The current draft of the SIP does not recommend any additional controls for the second implementation period (ending in 2028). The District does not know if it will be required to install and operate any of the SO2 control options referred to above in the future. However, the District has indicated to the NDEE that if the District were to incur major emission control costs at Gerald Gentleman Station, it could affect the future economic viability of Gerald Gentleman Station.

Clean Power Plan

On October 23, 2015, the EPA published the final Clean Power Plan ("CPP") rule addressing carbon dioxide reductions from existing fossil-fueled power plants. The final rule gave states significant responsibility for determining how to achieve the reduction targets through the development of a SIP. Each state was given a reduction target to be achieved by 2030, with interim reductions required between 2022 and 2029. The Nebraska reduction target for 2030 was 40% below 2012 emissions. On February 9, 2016, the U.S. Supreme Court issued a stay for the CPP until all legal challenges have been decided. The D.C. Circuit Court of Appeals heard oral arguments on September 27, 2016. The D.C. Circuit Court continued to hold the case in abeyance until its dismissal on September 17, 2019.

On August 31, 2018, the EPA issued the proposed CPP replacement rule now called the Affordable Clean Energy ("ACE") rule. Under Section 111(d) of the Clean Air Act the EPA must determine the Best System of Emissions Reduction ("BSER") for CO_2 at individual fossil-fuel fired steam generating units. On June 19, 2019, the EPA issued the final ACE rule. The final ACE rule repealed the CPP and makes the determination that BSER for CO_2 at individual fossil-fuel fired steam generating units to be Heat Rate Improvement ("HRI") projects. The EPA is also proposing to update the New Source Review process in a separate rulemaking. On September 17, 2019, the D.C. Circuit Court dismissed all legal challenges to the CPP as moot due to EPA repealing the CPP and replacing it with the ACE Rule.

On March 10, 2020, the District received an ICR from the NDEE for information pertaining to the ACE rule and a supplemental ICR received on May 8, 2020. The NDEE ICR requested information regarding the cost to install and operate the six HRI technologies listed in the final ACE rule at Gerald Gentleman Station Units No. 1 and No. 2 and Sheldon Station Units No. 1 and No. 2. The ICR also requested information on setting a CO_2 emission rate standard in pounds CO_2/MWh. The District submitted the information to the NDEE by the September 11, 2020 due date. The District will not know the final impact of the ACE rule until the NDEE develops their SIP.

It was announced on January 19, 2021 that the D.C. Circuit Court vacated the ACE rule. On June 30, 2022, the United States Supreme Court in West Virginia v. EPA held the CPP exceeded the authority of EPA under section 111 (d).

Endangered Species Act

The District applied to the U.S. Fish and Wildlife Service ("USFWS") under Section 10 of the Endangered Species Act ("ESA") for an Incidental Take Permit ("ITP") for the American burying beetle ("Beetle"), which is an endangered species. Issuance of an ITP is contingent upon USFWS acceptance of a Habitat Conservation Plan ("HCP") developed by the District to avoid, minimize and mitigate impacts on the Beetle. On February 8, 2019, the USFWS issued a Final Environmental Impact Statement ("FEIS") regarding the R-Project HCP to assess impacts on the environment. The FEIS describes the R-Project, certain alternatives, environmental impacts, cumulative impacts, comparison of alternatives and compliance and other environmental laws. On June 12, 2019, the USFWS issued its Record of Decision and the ITP. An escrow agreement was executed with USFWS to serve as financial assurance for the District's restoration obligations with respect to the R-Project.

On July 5, 2019, two nonprofit organizations and two other petitioners ("Petitioners") filed a petition for review in Colorado federal district court against three USFWS and Department of the Interior officials. The lawsuit challenged the ITP that the USFWS issued to the District for incidental take of the beetle from the construction, operation, and maintenance of the R-Project, alleging claims under the ESA, National Environmental Policy Act, and National Historic Preservation Act. The District intervened in the lawsuit to defend the ITP issuance and USFWS decisions.

On June 17, 2020, the district court issued its decision, finding in favor of the USFWS and the District on several counts, while also identifying certain discrete errors in the agency's decision-making process and finding for Petitioners on certain narrow grounds. The court on that basis vacated and remanded the ITP to the USFWS. Following the court's decision, and in compliance therewith, the District halted all construction on the R-Project, which construction had commenced in accordance with a stipulation between the parties to the litigation. The District, with notice to USFWS, took steps within the R-Project area to stabilize sites disturbed by those construction activities, protect the integrity of equipment and other project materials, and to remove debris and other potential hazards from landowners' property. The District will continue to keep the site in a stable condition while the R- Project construction remains paused following, and consistent with, the district court's decision.

The District and USFWS both decided not to appeal the district court's decision. The District is communicating with USFWS to address future ESA compliance issues for the R-Project in light of the district court's decision. Because the U.S. Army Corps of Engineers' ("Corps'") verification of the R-Project's use of Clean Water Act 404 Nationwide Permit 12 (the "404 Permit") relied on the USFWS's findings for the R-Project, the Corps suspended that permit on September 17, 2020. The District anticipates recommencing construction activities for the R-Project once the ESA compliance approach, and any other permit or agency authorization required for the ESA compliance approach for the R-Project, has been completed.

<u>Impact from Changes to Environmental Regulatory Requirements</u>
Any changes in the environmental regulatory requirements imposed by federal or state law which are applicable to the District's generating facilities could result in increased capital and operating costs being incurred by the District. The District is unable to predict whether any changes will be made to current environmental regulatory requirements, if such changes will be applicable to the District and the costs thereof to the District.

G. *Spencer Hydro* –
In mid-March 2019, multiple river basins in northern and eastern Nebraska, as well as river basins in the surrounding region, experienced unprecedented weather conditions as a result of exiting snowpack, blizzard conditions, frozen ground, significant rainfall and ice conditions on and around numerous rivers and their tributaries. The District sustained significant damage at the Spencer Hydro Facility, a small hydro plant on the Niobrara River in northern Nebraska accredited at 1.28 MW, which produced 10,509 MWh in 2018. The Spencer Hydro Facility, including the hydro plant and the concrete and earthen dam structures (collectively, the "Spencer Hydro Facility"), was damaged.

The District has been working with the Federal Emergency Management Agency ("FEMA") to make appropriate claims for reimbursement for the Spencer Hydro Facility. FEMA required a detailed study on the cost of rebuilding and the cost of removing the Spencer Hydro Facility, which the District pursued through an engineering firm. The study and cost estimates were submitted to FEMA. The study estimated the cost of decommissioning to be approximately $9.0 million. The District expects to eventually remove the Spencer Hydro Facility, which will require approval from the Nebraska Department of Natural Resources (the "NDNR") and permitting from other state and federal agencies.

The District was sued in a tort action in state court by the estate and family of the individual declared deceased following the events at the Spencer Hydro Facility for loss of life and property damage. Plaintiffs allege that their damages in the tort action exceed $5.0 million. The lawsuit has been settled and dismissed. The District has also been sued in state court for alleged inverse condemnation of property located further downstream. The inverse condemnation action claims damages of approximately $3.0 million. The case is in discovery. At this time, it is not possible to predict the outcome of the said lawsuit or any other claims that may arise.

13. LITIGATION:

Information on litigation related to the R-Project and the USFWS is included in Note 12.F., *Environmental-Endangered Species Act.*

Information on litigation related to the adverse weather conditions in March 2019 is included in Note 12.G., *Spencer Hydro.*

In 2017 and 2021, the Nebraska Department of Revenue ("NDOR") conducted sales and use tax audits on the District's records for the audit periods of June 1, 2014 through May 31, 2017 and June 1, 2017 through May 31, 2021, respectively. For both audits, NDOR issued Notices of Deficiency Determination to the District. Beyond the minor sales and use tax corrections contained in a normal audit Determination, the most significant disagreements between the District and NDOR related to NDOR's assessment of tax on the payments to municipalities under PRO Agreements. State legislation was passed in 2019 that exempted the payments under PRO Agreements from sales and use tax. The District filed Petitions for Redetermination to formally challenge the Deficiency Determinations. The Final Order from the Tax Commissioner dated May 27, 2022 upheld the Deficiency Determinations. The District petitioned for further review of the Final Order in the District Court of Lancaster, Nebraska. A hearing was held on February 1, 2023, and an Order was issued on March 16, 2023, in favor of the District, which reversed the Final Order from the Tax Commissioner and disallowed and abated the entire amount of the use tax deficiency, interest and penalties.

A number of claims and suits are pending against the District for alleged damages to persons and property and for other alleged liabilities arising out of matters usually incidental to the operation of a utility, such as the District. In the opinion of management, based upon the advice of its General Counsel, the aggregate amounts recoverable from the District, considering estimated amounts provided in the financial statements and insurance coverage, are not material.

REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

Calculation of Debt Service Ratios in accordance with the General Revenue Bond Resolution for the years ended December 31, (in 000's)	2022	2021
Operating revenues	$ 1,196,972	$ 1,221,778
Operating expenses	(1,079,904)	(1,064,354)
Operating income	117,068	157,424
Investment and other income (loss)	(10,194)	14,608
Debt and related expenses	(25,913)	(38,969)
Increase in net position	80,961	133,063
Add:		
Debt and related expenses (1)	25,913	38,969
Depreciation and amortization (2)	128,803	121,777
Payments to retail communities (3)	32,594	30,119
Amortization of current portion of financed nuclear fuel (4)	20,097	25,490
	207,407	216,355
Deduct:		
Investment income retained in construction funds (5)	180	162
Unrealized gain (loss) on investment securities	(8,396)	(2,976)
	(8,216)	(2,814)
Net revenues available for debt service under the General System Bond Resolution	$ 296,584	$ 352,232
General system bonded debt service (6)	128,222	130,138
Ratio of net revenues available for debt service (6)	2.31	2.71

(1) Debt and related expenses, exclusive of interest on customer deposits, is not an operating expense as defined in the General Resolution.
(2) Depreciation and amortization are not operating expenses as defined in the General Resolution.
(3) Under the provisions of the General Resolution, the payments required to be made by the District with respect to the PRO Agreements are to be made on the same basis as subordinated debt.
(4) General Revenue Bond financed nuclear fuel is not an operating expense as defined in the General Resolution. Amortization of nuclear fuel expense under the Taxable Revolving Credit Agreement is excluded from the debt service calculation as the District's obligation to make payments under the Taxable Revolving Credit Agreement is subordinate to the District's obligation to pay debt service on General Revenue Bonds.
(5) Interest income on investments held in construction funds is not Revenue as defined in the General Resolution.
(6) The District prefers to show all debt service paid from revenues, including debt service on redeemed Bonds, even though the General Resolution defines debt service only to include scheduled debt service. The decrease in the 2022 ratio of net revenues available for debt service (also referred to as debt service coverage) from 2021 was due to a decrease in net revenues. Net revenues were higher in 2021 due primarily to the recognition of surplus revenues from the 2021 February weather even for additional debt principal payments on the revolving credit agreement. The debt service coverage for 2022 included debt service on the General Revenue Bonds, 2012 Series B, redeemed in December 2022. If the debt service on the said General Revenue Bonds so redeemed were excluded for 2022, the debt service coverage for 2022 was 2.76 times.

Schedules of Changes in the Net OPEB (Asset) Liability and Related Ratios using a January 1 Measurement Date (in 000's)

Total OPEB Liability	2022	2021	2020	2019	2018	2017	2016
Service Cost	$ 2,663	$ 2,103	$ 2,299	$ 2,771	$ 2,760	$ 3,322	$ 3,229
Interest	18,237	18,775	19,604	19,661	20,032	20,658	19,876
Changes of Benefit Terms	-	8,598	-	-	-	-	-
Differences between Expected and Actual Experiences	(7,054)	(20,995)	(19,961)	(8,686)	(19,570)	(203)	13,657
Changes of Assumptions	12,621	9,367	(1,608)	(751)	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(15,710)	(14,026)	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	10,757	3,822	(12,473)	(1,065)	(6,607)	(8,489)	10,711
Total OPEB Liability (Beginning)	309,021	305,199	317,672	318,737	325,344	333,833	323,122
Total OPEB Liability (Ending) (a)	$319,778	$ 309,021	$ 305,199	$ 317,672	$ 318,737	$ 325,344	$ 333,833
Plan Fiduciary Net Position							
Contributions	$ 28,283	$ 28,283	$ 41,084	$ 56,706	$ 28,439	$ 74,711	$ 28,242
Net Investment Income (Loss)	46,479	47,237	41,733	(6,892)	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(15,710)	(14,026)	(12,807)	(14,060)	(15,414)	(13,459)	(16,902)
Administrative Expense	(259)	(205)	(188)	(130)	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	58,793	61,289	69,822	35,624	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	343,549	282,260	212,438	176,814	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	$402,342	$ 343,549	$ 282,260	$ 212,438	$ 176,814	$ 142,509	$ 75,224
Net OPEB (Asset) Liability (Ending) (a) - (b)	$ (82,564)	$ (34,528)	$ 22,939	$ 105,234	$ 141,923	$ 182,835	$ 258,609
Net Position as a % of Total OPEB Liability	125.8%	111.2%	92.5%	66.9%	55.5%	43.8%	22.5%

Schedules of OPEB Contributions for Years Ended December 31, (in 000's)

	2022	2021	2020	2019	2018	2017	2016
Actuarially Determined Contribution	$ 2,847	$ 2,871	$ 6,676	$ 12,967	$ 18,572	$21,006	$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	6,294	28,283	28,283	41,084	56,706	28,439	74,712
Contribution Deficiency (Excess)	$ (3,447)	$(25,412)	$(21,607)	$(28,117)	$(38,134)	$ (7,433)	$(46,429)

Schedules of Investment Returns for Years Ended December 31,

	2022	2021	2020	2019	2018	2017	2016
Annual Money-Weighted Rate of Return, Net of Investment Expense	(16.6%)	13.3%	15.6%	18.9%	(3.6%)	14.2%	5.8%

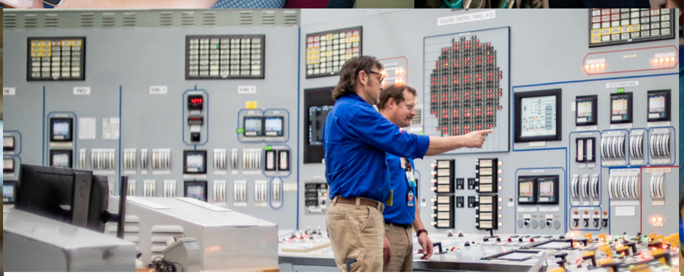
NOTES TO REQUIRED SUPPLEMENTARY INFORMATION (UNAUDITED)

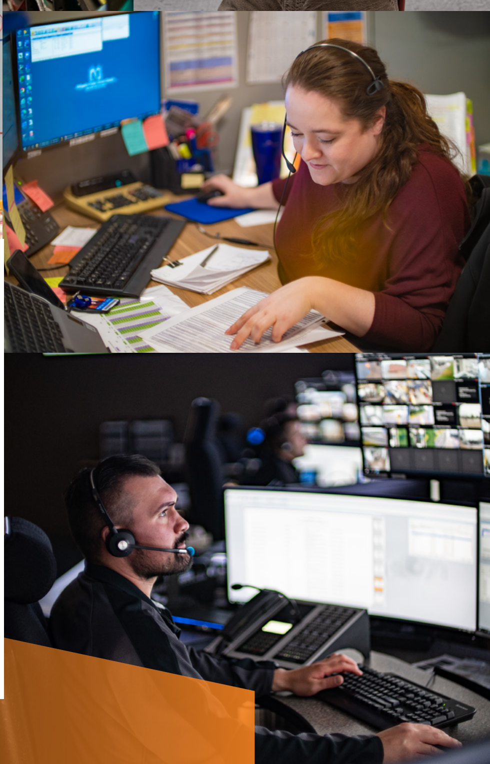
GASB guidance requiring this information was implemented by the District in 2016. The OPEB schedules are intended to show information for ten years. Additional years will be displayed when available.

Valuation date – Actuarially determined contribution rates are calculated as of January 1, one year prior to the end of the fiscal year in which contributions are reported. The changes in benefit terms for 2021 were for the addition of the RRA.

Methods and assumptions used to determine contribution rates –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	11-year closed period for 2022, 12-year closed period for 2021 13-year closed period for 2020, 14-year closed period for 2019 15-year closed period for 2018, 16-year closed period for 2017 17-year closed period for 2016
Asset valuation method	5-year smoothed market
Healthcare cost trend rates	Pre-Medicare: 6.4% initial, ultimate 4.5% for 2022 Post-Medicare: 6.7% initial, ultimate 4.5% for 2022 Pre-Medicare: 6.7% initial, ultimate 4.5% for 2021 Post-Medicare: 7.1% initial, ultimate 4.5% for 2021 Pre-Medicare: 7.1% initial, ultimate 4.5% for 2020 Post-Medicare: 7.8% initial, ultimate 4.5% for 2020 Pre-Medicare: 7.4% initial, ultimate 4.5% for 2019 Post-Medicare: 8.2% initial, ultimate 4.5% for 2019 Pre-Medicare: 7.7% initial, ultimate 4.5% for 2018 Post-Medicare: 8.7% initial, ultimate 4.5% for 2018 Pre-Medicare: 7.3% initial, ultimate 4.5% for 2017 Post-Medicare: 9.1% initial, ultimate 4.5% for 2017 Pre-Medicare: 8.0% initial, ultimate 4.5% for 2016 Post-Medicare: 6.75% initial, ultimate 4.5% for 2016
RRA increase rate	3.0%
Administrative cost trend	3.0%
Inflation	2.2% for 2022, 2.1% for 2021, 2.2% for 2020, 2.3% for 2019 and 2018, 2.1% for 2017 and 2016
Salary increases	4.0%
Investment rate of return	5.75%, net of investment expense, including inflation for 2022 6.0%, net of investment expense, including inflation for 2021 6.25%, net of investment expense, including inflation for 2020 through 2016
Discount rate	5.75% for 2022, 6.0% for 2021, 6.25% for 2020 through 2016 based on expected long-term return on assets used to finance the payment of plan benefits
Mortality	Pub-2010 "General" table with generational projection using Scale MP-2021 for 2022 Pub-2010 "General" table with generational projection using Scale MP-2020 for 2021 Pub-2010 "General" table with generational projection using Scale MP-2019 for 2020 Pub-2010 "General" table with generational projection using Scale MP-2018 for 2019 RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2017 with generational projection for 2018 RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2016 with generational projection for 2017 RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2015 with generational projection for 2016
Retirement and withdrawal rates	Varies by age
Spousal benefits	80% of males and 60% of females are assumed to have spouses who will elect coverage. Males are assumed to be two years older than their spouses. Females are assumed to be two years younger for 2021 through 2019 80% of males and 30% of females are assumed to have spouses who will elect coverage. Males are assumed to be three years older than their spouses. Females are assumed to be three years younger for 2018 through 2016
Participation rate	95% for 2022 through 2019, 100% for 2018 through 2016





Nebraska Public Power District

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