Nebraska Public Power District
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NLS2019032 50.71(b)
May 14, 2019

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Subject: Nebraska Public Power District 2018 Financial Report
Cooper Nuclear Station, Docket No. 50-298, DPR-46

Dear Sir or Madam:

The purpose of this letter is to transmit the Nebraska Public Power District (NPPD) Financial Report for the calendar year 2018 in accordance with the requirements of 10 CFR 50.71(b). Copies of this report are being distributed in accordance with 10 CFR 50.4.

This letter does not contain any commitments.

Should you have any questions or require additional information, please contact me at (402) 825-2788.

Sincerely,

Jim Shaw
Licensing Manager

/jo

Enclosure - NPPD 2018 Financial Report

cc: Regional Administrator w/enclosure
USNRC - Region IV

Cooper Project Manager w/enclosure
USNRC - NRR Plant Licensing Branch IV

Senior Resident Inspector w/enclosure
USNRC - CNS

NPG Distribution w/o enclosure

CNS Records w/enclosure

M004
NRR

NPPD 2018 Financial Report

2018
FINANCIAL REPORT *of the*
NEBRASKA PUBLIC POWER DISTRICT

2018
FINANCIAL REPORT
NEBRASKA PUBLIC POWER DISTRICT

2018 YEAR AT A GLANCE

KILOWATT - HOUR SALES		20.0	BILLION
OPERATING REVENUES	$	1,144.9	MILLION
COST OF POWER PURCHASED AND GENERATED	$	611.4	MILLION
OTHER OPERATING EXPENSES	$	413.8	MILLION
INVESTMENT AND OTHER INCOME	$	26.9	MILLION
DEBT AND RELATED EXPENSES	$	63.9	MILLION
INCREASE IN NET POSITION	$	82.7	MILLION
DEBT SERVICE COVERAGE		2.03	TIMES

2018 STATISTICAL REVIEW (Unaudited)

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	10.39 ¢	12.42 ¢	72,240	857,448	4.3	$ 106,471	9.3
Commercial	8.40 ¢	9.80 ¢	19,539	1,129,750	5.6	110,706	9.7
Industrial	4.92 ¢	5.25 ¢	59	1,407,276	7.0	73,911	6.5
Total Retail Sales	7.46 ¢	8.58 ¢	91,838	3,394,474	16.9	291,088	25.5
Wholesale:							
Municipalities[2]		6.18 ¢	44	1,694,601	8.5	104,800	9.2
Municipalities (Partial Requirements)[3]		5.47 ¢	2	147,429	0.6	8,057	0.6
Public Power Districts and Cooperatives[2]		5.90 ¢	23	7,506,935	37.5	443,113	38.7
Public Power Districts (Part Req)[3]		5.26 ¢	1	190,473	1.0	10,017	0.9
Total Firm Wholesale Sales		5.93 ¢	70	9,539,438	47.6	565,987	49.4
Total Firm Retail and Wholesale Sales		6.63 ¢	91,908	12,933,912	64.5	857,075	74.9
Participation Sales		3.64 ¢	5	1,753,411	8.8	63,906	5.6
Other Sales[4]		2.62 ¢	2	5,338,192	26.7	140,048	12.2
Total Electric Energy Sales		5.30 ¢	91,915	20,025,515	100.0	1,061,029	92.7
Other Operating Revenues[5]						79,756	7.0
Unearned Revenues[6]						4,073	0.3
Total Operating Revenues						$1,144,858	100.0

COST OF POWER PURCHASED AND GENERATED	MWh Amount	MWh %	Costs (in 000's) Amount	Costs (in 000's) %
Production[7]	16,100,177	77.1	$ 449,690	73.6
Power Purchased	4,775,339	22.9	161,665	26.4
Total Production and Power Purchased	20,875,516	100.0	$ 611,355	100.0

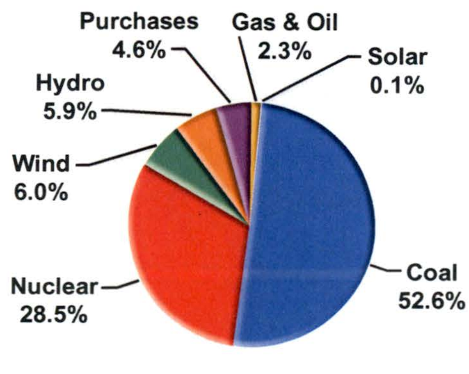
CONTRACTUAL AND TAX PAYMENTS (in 000's)[1]	Amount
Payments to Retail Communities	$ 27,745
Payments in Lieu of Taxes	10,354
Total Contractual and Tax Payments	$ 38,099

OTHER	Amount
Miles of Transmission and Subtransmission Lines in Service	5,341
Number of Full-Time Employees	1,905

(1) Customer collections for taxes/transfers to other governments are excluded from base rates.
(2) Sales are total requirements, subject to certain exceptions.
(3) Sales are to customers who limited their requirements under the 2002 Contracts. The average rate was lower than total requirements customers due to the exclusion of certain transmission costs from the wholesale rate as cost recovery was through the Southwest Power Pool ("SPP") transmission tariff and included in Other Operating Revenues.
(4) Includes sales in SPP and nonfirm sales to other utilities.
(5) Includes revenues for transmission and other miscellaneous revenues.
(6) 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.
(7) 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 ("District") includes Management's Discussion and Analysis, Financial Statements, Notes to Financial Statements, and Supplemental Schedules. The financial statements consist of the Balance Sheets, Statements of Revenues, Expenses, and Changes in Net Position, Statements of Cash Flows, and Supplemental Schedules.

The following Management's Discussion and Analysis ("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 and Notes to Financial Statements.

The Balance Sheets present assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position as of December 31, 2018 and 2017. The Statements of Revenues, Expenses, and Changes in Net Position present the operating results for the years 2018 and 2017. The Statements of Cash Flows present the sources and uses of cash and cash equivalents for the years 2018 and 2017. 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, 2018 and 2017, and the results of operations for the years 2018 and 2017. The Supplemental Schedules 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 District's chartered territory includes all or parts of 86 of the State's 93 counties and more than 400 municipalities in the State. 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.

The District operates an integrated electric utility system including facilities for generation, transmission, and distribution of electric power and energy for sales at retail and wholesale. Management and operation of the District is accomplished with a staff of 1,905 full-time employees as of December 31, 2018. 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 anytime peak load in 2018 of 2,726.2 megawatts ("MW"), the District had available 3,686.0 MW of capacity resources that included 3,078.1 MW of generation capacity from 12 owned and operated generating plants and 22 plants over which the District has operating control, 444.3 MW of firm capacity purchases from the Western Area Power Administration, and 163.6 MW of a capacity purchase from Omaha Public Power District's ("OPPD")

Nebraska City Station Unit 2 ("NC2") coal-fired plant. Of the total capacity resources, 186.2 MW are being sold via participation sales or other capacity sales agreements, leaving 3,499.8 MW to serve firm retail and wholesale customers and to meet capacity reserve requirements. The highest summer anytime peak load of 3,030.3 MW was established in July 2012 and the highest winter anytime peak load of 2,252.0 MW was established in January 2014 for firm requirements customers.

The following table shows the District's capacity resources from generation and respective summer 2018 accredited capability.

	CAPACITY RESOURCES		
Type	Number of Plants[1]	Summer 2018 Accredited Capability (MW) [2]	Percent of Total
Steam - Conventional [3]	3	1,683.3	54.7
Steam - Nuclear	1	770.0	25.0
Combined Cycle	1	220.0	7.2
Combustion Turbine [4]	3	126.7	4.1
Hydro	6	110.8	3.6
Diesel	12	93.4	3.0
Wind [5]	8	73.9	2.4
	34	3,078.1	100.0

(1) Includes three hydro plants and 12 diesel plants under contract to the District.
(2) 2018 summer accredited net capability based on SPP criteria.
(3) Includes Gerald Gentleman Station ("GGS"), Sheldon Station ("Sheldon"), and Canaday Station.
(4) Includes the Hallam, Hebron and McCook peaking turbines.
(5) Includes Ainsworth Wind Energy Facility ("Ainsworth") and seven wind facilities under contract to the District.

The following table shows the generation facilities owned by the District and their respective fuel types, summer 2018 accredited capability, and in-service dates.

	DISTRICT OWNED GENERATION FACILITIES		
Type	Fuel Type	Summer 2018 Accredited Capability (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	220.0	2005
Sheldon Station Units No. 1 and No. 2	Coal	219.0	1961, 1968
Combustion Turbines (3 generating plants)	Oil or Natural Gas	126.7	1973
Canaday Station	Natural Gas	99.3	1958
Hydro (3 generating plants)	Water	25.3	1887, 1927, 1939
Ainsworth Wind Energy Facility[2]	Wind	7.7	2005
		2,833.0	

(1) 2018 summer accredited net capability based on SPP criteria.
(2) Nominally rated at 60 MW.

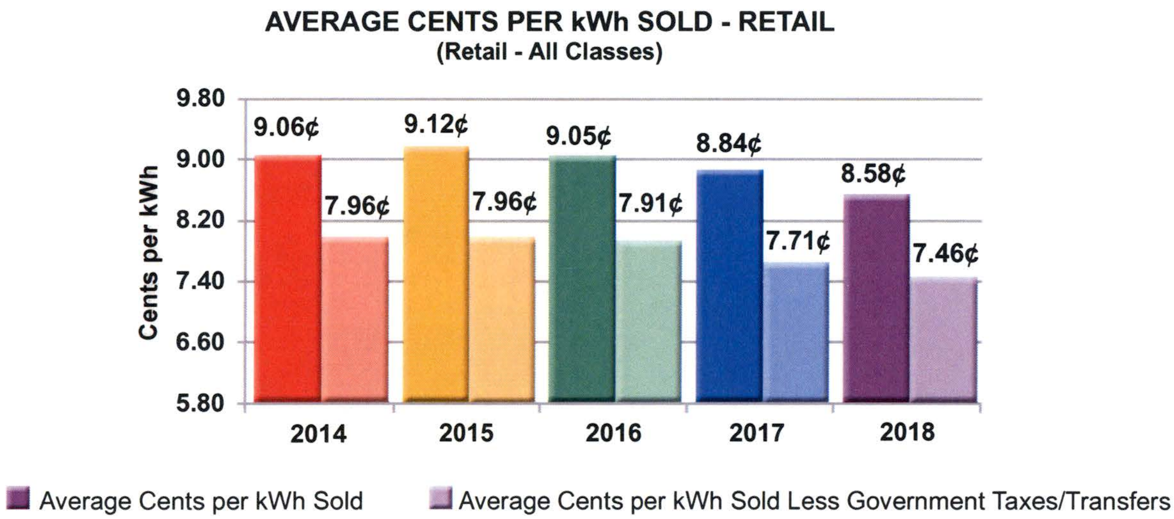
THE CUSTOMERS

Retail and Wholesale Customers

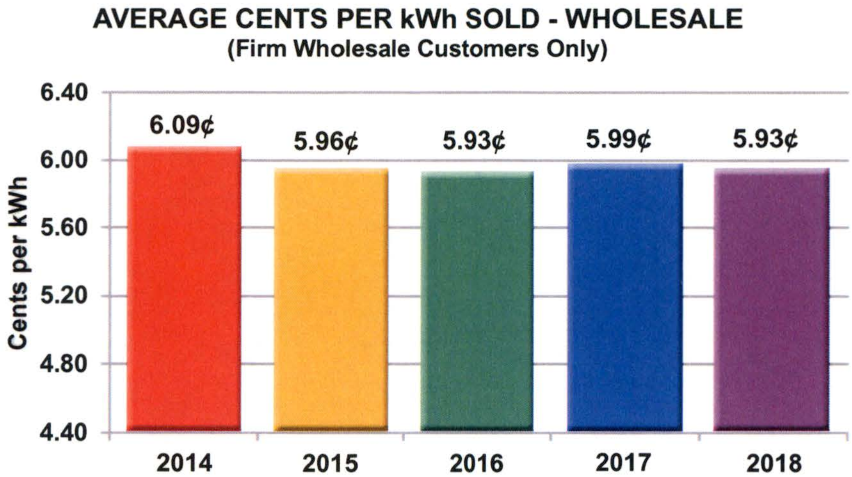
In 2018, the District served an average of 91,838 retail customers. The District's retail service territory includes 79 municipal-owned distribution systems operated by the District for the municipality pursuant to a Professional Retail Operations ("PRO") Agreement. Details of the District's PRO Agreements are included in Note 12 in the Notes to Financial Statements.

The District serves its wholesale customers under total 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 sales contracts with a substantial number of its wholesale customers (the "2016 Contracts"). The 2016 Contracts replaced wholesale contracts that were entered into in 2002 (the "2002 Contracts"). Wholesale customers served under the 2016 Contracts include 22 public power districts, one cooperative and 37 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 include one public power district and nine municipalities. The District's 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 National Rural Utilities Cooperative Finance Corporation Key Ratio Trend Analysis (Ratio 88) (the "CFC Data"). The District's wholesale power costs percentile was 26.0% for 2017, based on the latest available data. Details of the District's Wholesale Power Contracts are included in Note 12 in the Notes to Financial Statements.

The following chart shows the District's average retail cents per kWh for the years ended December 31, 2014 through 2018. 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 following chart shows the District's average wholesale cents per kWh for the years ended December 31, 2014 through 2018.



Participation 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 Lincoln Electric System ("LES"), Municipal Energy Agency of Nebraska ("MEAN"), OPPD, Grand Island Utilities ("Grand Island"), and JEA. The District also sells 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 5,341 miles of transmission and subtransmission lines, encompassing nearly the entire State. 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 and Energy Sales

The following table shows customers, energy sales, and peak loads of the System, including participation sales, in each of the three years, 2016 through 2018.

			Megawatt-Hour Sales				Anytime Peak Load (MW)
Calendar Year	Average Number of Retail Customers	Wholesale Customers(1)	Native Load Sales(2)	Percentage Growth	Total Sales (3)	Percentage Growth(4)	Busbar Native Load
2016	91,457	78	12,901,989	2.6	18,902,173	(10.0)	2,963.7
2017	91,614	78	13,061,979	1.2	19,568,548	3.5	2,891.5
2018	91,838	77	12,933,912	(1.0)	20,025,515	2.3	2,726.2

(1) At the end of 2018, includes sales to firm wholesale customers, participation customers (LES, MEAN, JEA, OPPD, Grand Island), and a yearly average of two nonfirm customers. The decrease in the average number of wholesale customers by one in 2018 from 2017 was due to a merger of Seward County Public Power District with Norris Public Power District. In 2016, three of the District's municipal wholesale customers began purchasing power from three of the District's public power district wholesale customers, and one of the District's municipal wholesale customers allowed their contract to terminate.

(2) Native load sales include 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.

(3) Total sales from the System include sales to LES from GGS and Sheldon, which sales from Sheldon terminated on December 31,2017; to MEAN, JEA, OPPD, and Grand Island from Ainsworth, which sales commenced October 1, 2005, and terminates on September 30, 2025, but JEA has given notice to terminate its sale effective December 31, 2019; to OPPD, MEAN, LES and Grand Island from Elkhorn Ridge Wind Facility, which sales commenced March 1, 2009, and terminates on February 28, 2029; to MEAN from GGS and Cooper Nuclear Station ("CNS"), which sale commenced January 1, 2011, and terminates on December 31, 2023; to MEAN, LES and Grand Island from Laredo Ridge Wind Facility, which sales commenced February 1, 2011, and terminates on January 31, 2031; to OPPD, LES and Grand Island from Broken Bow I Wind Facility, which sales commenced December 1, 2012, and terminates on November 30, 2032; to OPPD, LES and MEAN from Crofton Bluffs Wind Facility, which sales commenced November 1, 2012, and terminates on October 31, 2032; and to OPPD from Broken Bow II Wind Facility which sale commenced October 1, 2014, and terminates on September 30, 2039.

(4) The increase in percentage growth from 2017 to 2018 for total sales was due primarily to nonfirm energy sales. The increase in percentage growth from 2016 to 2017 was due primarily to additional nonfirm energy sales from CNS as a result of 2017 being a non-outage year for the unit.

FINANCIAL INFORMATION

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

CONDENSED BALANCE SHEETS (in 000's)

As of December 31,	2018	2017	2016
Current Assets	$ 924,108	$ 858,872	$ 775,479
Special Purpose Funds	727,607	746,448	782,857
Utility Plant, Net	2,562,556	2,569,898	2,595,767
Other Long-Term Assets	351,046	383,701	406,149
Deferred Outflows of Resources	333,343	295,402	344,331
Total Assets and Deferred Outflows	$ 4,898,660	$ 4,854,321	$ 4,904,583
Current Liabilities	$ 380,675	$ 370,501	$ 287,322
Long-Term Debt	1,506,605	1,617,269	1,867,768
Other Long-Term Liabilities	997,359	1,028,467	1,063,118
Deferred Inflows of Resources	444,880	351,651	271,258
Net Position	1,569,141	1,486,433	1,415,117
Total Liabilities, Deferred Inflows, and Net Position	$ 4,898,660	$ 4,854,321	$ 4,904,583

CONDENSED RESULTS OF OPERATIONS (in 000's)

For the years ended December 31,	2018	2017	2016
Operating Revenues	$ 1,144,858	$ 1,101,642	$ 1,153,997
Operating Expenses	(1,025,185)	(988,931)	(1,040,715)
Operating Income	119,673	112,711	113,282
Investment and Other Income	26,896	23,591	31,772
Debt and Related Expenses	(63,861)	(64,986)	(62,121)
Increase in Net Position	$ 82,708	$ 71,316	$ 82,933

SOURCES OF OPERATING REVENUES (in 000's)

For the years ended December 31,	2018	2017	2016
Firm Retail and Wholesale Sales	$ 857,075	$ 875,312	$ 865,661
Participation Sales	63,906	73,199	77,996
Other Sales	140,048	112,209	89,492
Other Operating Revenues	79,756	76,182	66,060
Unearned Revenues	4,073	(35,260)	54,788
Total Operating Revenues	$ 1,144,858	$ 1,101,642	$ 1,153,997

CONDENSED STATEMENTS OF CASH FLOWS (in 000's)

For the years ended December 31,	2018	2017	2016
Net Cash Provided by Operating Activities	$ 363,088	$ 365,097	$ 253,711
Net Cash Provided by (Used in) Investing Activities	(45,884)	(107,438)	2,374
Net Cash Used in Capital and Financing Activities	(319,506)	(332,584)	(238,416)
Net Increase (Decrease) in Cash and Cash Equivalents	(2,302)	(74,925)	17,669
Cash and Cash Equivalents, Beginning of Year	27,804	102,729	85,060
Cash and Cash Equivalents, End of Year	$ 25,502	$ 27,804	$ 102,729

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 costs and government taxes and transfers. 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 in the rate stabilization account. Any amounts in excess of the limits may 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.

There was no change to the wholesale or retail base rates on January 1, 2019 and January 1, 2018. On February 1, 2019, the District implemented a 12-month Production Cost Adjustment ("PCA") rate to refund $26.8 million to its wholesale customers for production rate stabilization funds in excess of the ten percent accumulated limit. The PCA resulted in an average 3.5% decrease in wholesale rates. The District implemented a 0.6% increase in the District's wholesale rates on January 1, 2017, for all customers. No increase in retail rates was implemented in 2017. The District implemented a 0.6% increase in the District's wholesale rates on January 1, 2016, for those wholesale customers who signed the new 2016 20-year wholesale power contract, and a 3.8% increase in the District's wholesale rates on January 1, 2016, for those wholesale customers who remained under the 2002 20-year wholesale power contract. The rate increase was higher for the 2002 Contracts as these customers will pay their share of a catch-up in funding for OPEB costs related to prior service through rates prior to the expiration of their contracts in 2021. The District financed with taxable debt the 2016 Contracts customers' share of the OPEB catch-up trust funding for the years 2016, 2017 and 2018. The customers under the 2016 Contracts will commence payment through rate collections of the related debt service for their share of the catch-up in funding for OPEB costs beginning in 2022, the year after the expiration of the 2002 Contracts, and continue making payments through 2033. No increase in retail rates was implemented in 2016. Details of the District's Wholesale Power Contracts are included in Note 12 in the Notes to Financial Statements.

Revenues from firm sales decreased $18.2 million, or 2.1%, from $875.3 million in 2017 to $857.1 in 2018. The decrease was primarily due to a 1.0% decrease in native load energy sales as a result of two municipalities and one public power district under the 2002 Contracts reducing their purchases from the District and the collection of transmission revenues for partial requirements customers through the SPP transmission tariff instead of the wholesale rate. These transmission revenues are recorded in Other Operating Revenues. Revenues from firm sales increased $9.6 million, or 1.1%, from $865.7 million in 2016 to $875.3 million in 2017. The increase in revenue was due primarily to a weather-related 1.2% increase in energy sales.

Revenues from Participation Sales

The District has participation sales agreements with other utilities that share operating expenses on a pro rata basis. Revenues from participation sales decreased from $73.2 million in 2017 to $63.9 million in 2018. The reduction was primarily due to the December 31, 2017 termination of a participation agreement with LES to purchase 30% of the output of Sheldon. Revenues from participation sales decreased from $78.0 million in 2016 to $73.2 million in 2017, a reduction of $4.8 million. The reduction was due primarily to lower demand revenues for GGS and CNS, along with lower wind participation energy sales.

Revenues from Other Sales

Other sales consist of sales in SPP's Integrated Market and nonfirm sales to other utilities. TEA, of which the District is a member, has energy marketing responsibilities for the District's other and nonfirm off-system sales and the related management of credit risks. Other sales increased from $112.2 million in 2017 to $140.0 in 2018, an increase of $27.8 million. The increase was a result of higher nonfirm sales and higher prices in the SPP Integrated Market. Other sales increased from $89.5 million in 2016 to $112.2 million in 2017, an increase of $22.7 million. The increase was a result of higher energy sales due to no refueling and maintenance outage at CNS and higher prices in the SPP Integrated Market due to higher natural gas prices.

Other Operating Revenues

Other operating revenues consist primarily of revenues for transmission and other miscellaneous revenues. These revenues were $79.8 million, $76.2 million, and $66.1 million in 2018, 2017, and 2016, respectively. The majority of these revenues were from other SPP transmission customers for their share of qualifying transmission upgrade projects of the District. The increase in these revenues from 2017 to 2018 was partially due to additional SPP transmission revenues from wholesale customers who have become partial requirements customers under the 2002 Contracts, and must purchase transmission service through SPP.

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 taken into account 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 taken into account in setting rates.

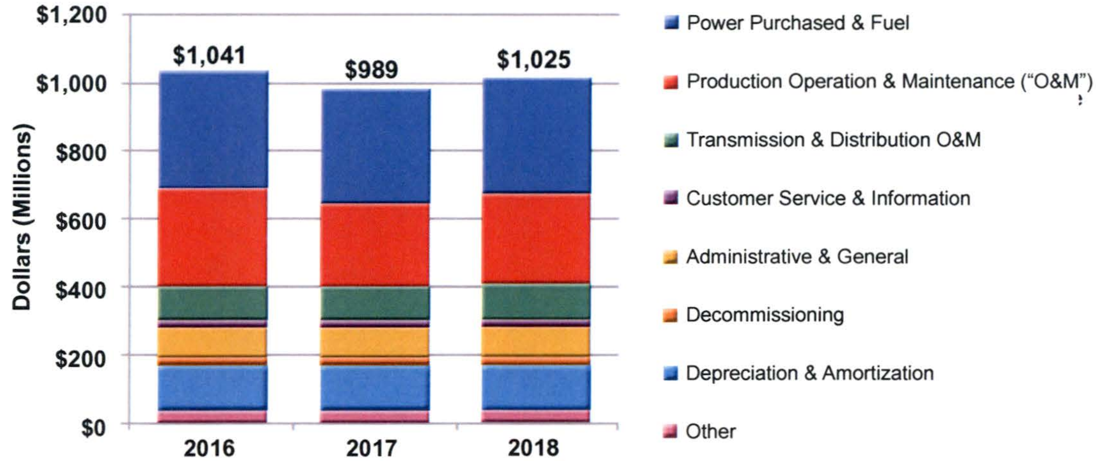
The following table shows the increase (decrease) in revenues from rate stabilization and other regulatory accounts for the years 2018, 2017 and 2016, respectively.

	2018	2017	2016
Surplus revenues deferred to future periods	$ (70.0)	$ (44.9)	$ (10.0)
Refunded revenues from prior periods	29.1	6.7	17.4
CNS outage collections	20.0	(20.0)	24.7
OPEB deferred collections	23.5	23.0	22.7
Revenues from settlement agreements	1.5	-	-
	$ 4.1	$ (35.2)	$ 54.8

The balance of the regulatory liability for unearned revenues to be applied as credits against revenue requirements in future rate periods was $247.9 million, $206.9 million, and $168.7 million, as of December 31, 2018, 2017, and 2016, respectively.

Operating Expenses

The following chart illustrates operating expenses for the years ended December 31, 2016 through 2018.



Total operating expenses in 2018 were $1,025.2 million, an increase of $36.3 million over 2017. Total operating expenses in 2017 were $988.9 million, a decrease of $51.8 million from 2016. The changes were due primarily to the following:

Power purchased and fuel expenses were $336.4 million, $342.8 million, and $347.6 million in 2018, 2017, and 2016, respectively. These expenses decreased $6.4 million in 2018 as compared to 2017 due primarily to lower fuel costs at GGS and lower fuel consumption at CNS due to the 2018 refueling outage. These expenses decreased $4.8 million in 2017 as compared to 2016 due primarily to fewer energy purchases in the SPP Integrated Market as there was no refueling and maintenance outage at CNS. The favorable power purchased variance was partially offset by an unfavorable fuel variance from higher generation in 2017.

Production operation and maintenance expenses were $275.0 million, $243.3 million, and $287.7 million in 2018, 2017, and 2016, respectively. These costs increased $31.7 million in 2018 due primarily to the costs associated with the planned refueling and maintenance outage at CNS. These costs decreased $44.4 million in 2017 as compared to 2016 due primarily to the costs associated with a planned refueling and maintenance outage at CNS in 2016. No such outage occurred in 2017.

Transmission and distribution operation and maintenance expenses were $105.2 million, $100.9 million, and $102.0 million in 2018, 2017, and 2016, respectively. These costs increased by $4.3 million in 2018 as compared to 2017 due primarily to higher fees charged by SPP for the District's share of transmission expenses and qualifying transmission upgrade projects. These costs decreased $1.1 million in 2017 as compared to 2016.

Customer service and information expenses were $16.8 million, $16.0 million, and $17.7 million in 2018, 2017, and 2016, respectively.

Administrative and general expenses were $104.9 million, $106.2 million, and $94.1 million in 2018, 2017, and 2016, respectively. Administrative and general expenses decreased $1.3 million in 2018 as compared to 2017. These costs increased $12.1 million in 2017 as compared to 2016 due primarily to a reclassification in 2017 to include all OPEB costs with administrative and general expense, a portion of these costs were included in operation and maintenance expense in prior years.

Decommissioning expenses were $15.7 million, $19.9 million, and $21.4 million in 2018, 2017, and 2016, respectively. Prior to 2017, decommissioning expenses only represented the net amount accrued each year for the future decommissioning of CNS. Commencing in 2017, decommissioning expenses also included amounts for the future decommissioning of certain non-nuclear utility plant assets. 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 decreased $4.2 million in 2018 as compared to 2017, primarily due to a decrease in investment income for decommissioning funds. Decommissioning expenses decreased $1.5 million in 2017 as compared to 2016. This decrease was due to a $7.4 million decrease in investment income for the nuclear facility decommissioning fund, which was partially offset by $5.9 million in collections for decommissioning of certain non-nuclear utility plant assets.

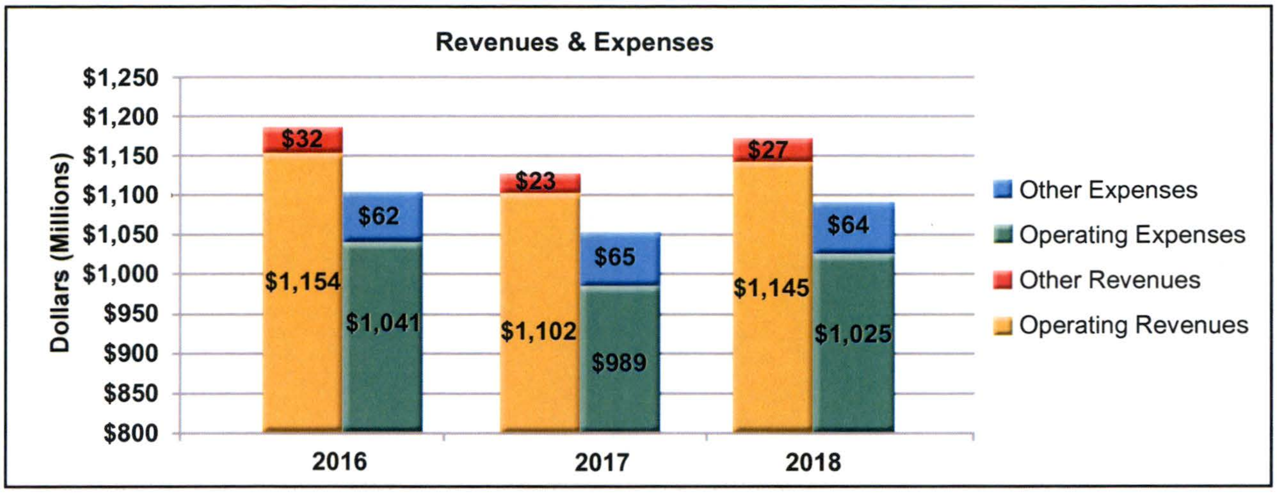
Depreciation and amortization expenses were $133.1 million, $122.6 million, and $133.7 million in 2018, 2017, and 2016, respectively. The increase in depreciation and amortization expenses from 2017 to 2018 was primarily due to amortization of costs related to the advanced metering infrastructure project for retail customers.

Increase in Net Position

The increase in net position was $82.7 million, $71.3 million, and $82.9 million in 2018, 2017, and 2016, respectively. The change in net position in 2018 as compared to 2017 increased $11.4 million and was due primarily to an increase in revenue collections for principal payments for debt service and the change in unrealized market gains on investments, which was partially offset by a decrease in revenue collections for capital projects and higher depreciation expense.

The change in net position in 2017 as compared to 2016 decreased $11.6 million and was due primarily to a decrease in 2017 revenue requirements from reduced collections for capital projects and principal payments for debt service, an increase in unrealized investment losses and lower capitalization of interest during construction. These decreases in net position were partially offset by a reduction in depreciation expense.

The following chart illustrates the District's operating revenues, other revenues, operating expenses, and other expenses for the years ended December 31, 2016 through 2018.



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. The District's debt service coverage ratio was 2.03, 2.13, and 1.98 in 2018, 2017, and 2016, respectively. The coverage was provided primarily by the amounts collected in operating revenues for utility plant additions, for principal and interest payments on outstanding revolving credit agreements and notes, and for payments to those municipalities served by the District under long-term PRO Agreements. The decrease in the 2018 debt service coverage ratio from 2017 was primarily due to an increase in the required debt service deposits. The increase in the 2017 debt service coverage ratio over 2016 was primarily due to a decrease in the required debt service deposits.

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 revenue bonds were as follows:

Moody's Investors Service	A1	(stable outlook)
Standard & Poor's Ratings Services	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 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.

In January 2019, the following activity occurred related to General Revenue Bonds:

- Issued $36.0 million of General Revenue Bonds, 2019 Series A, at a premium of $5.2 million, to refund $50.4 million General Revenue Bonds, 2009 Series A (Taxable Build America Bonds). The refunding was completed with $41.2 million of the proceeds from General Revenue Bonds, 2019 Series A, $3.7 million from the Tax-Exempt Revolving Credit Agreement ("TERCA"), and $5.5 million of other available funds. As a result, total debt service payments over the life of the bonds was reduced by $20.4 million, which resulted in present value savings of $6.6 million.
- Defeased certain of the General Revenue Bonds, 2017 Series A, with an outstanding principal amount that aggregated $7.3 million.
- Called the remaining outstanding General Revenue Bonds, 2009 Series C, with a principal amount that aggregated $0.4 million.

The District expects to issue additional revenue bonds in 2019 for an SPP Notice to Construct project for 225 miles of 345 kV transmission line, budgeted at $417.0 million, which project may be financed in whole or in part, beginning in 2019 and throughout its scheduled completion in 2021.

In July 2018, the Taxable Revolving Credit Agreement ("TRCA") was renewed through July 29, 2021.

In January 2018, the District called the remaining outstanding General Revenue Bonds, 2012 Series C, with a principal amount that aggregated $4.2 million.

In June 2017, the District executed a TERCA with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $150.0 million, which replaced its Commercial Paper Notes program.

In April 2017, the District issued General Revenue Bonds, 2017 Series A and 2017 Series B, in the amount of $86.0 million to refund the General Revenue Bonds, 2007 Series B. The refunding reduced total debt service payments over the life of the bonds by $11.8 million, which resulted in present value savings of $10.0 million.

Details of the District's debt balances and activity are included in Note 7 in the Notes to Financial Statements.

CAPITAL REQUIREMENTS

The Board-authorized capital projects totaled approximately $85.5 million, $85.0 million, and $109.5 million, in 2018, 2017, and 2016, respectively. The District's capital requirements are funded with monies generated from operations, debt proceeds, and other available reserve funds.

Capital projects for 2018 included:

- $24.3 million for retrofit of the low-pressure turbine for GGS Unit 2
- $5.0 million for a south building addition for training and fleet at the Operations Center in York, Nebraska
- $4.5 million for refurbishment of the main generator exciter at CNS
- $4.4 million for a plant management information system at CNS
- $4.3 million for a reactor feed pump turbine B overhaul at CNS

Capital projects for 2017 included:

- $14.7 million for implementation of Advanced/Smart Metering and Interfaces
- $11.2 million for construction of an evaporation pond at GGS
- $6.4 million for refurbishment of a 115 kV substation in Beatrice, Nebraska

Capital projects for 2016 included:

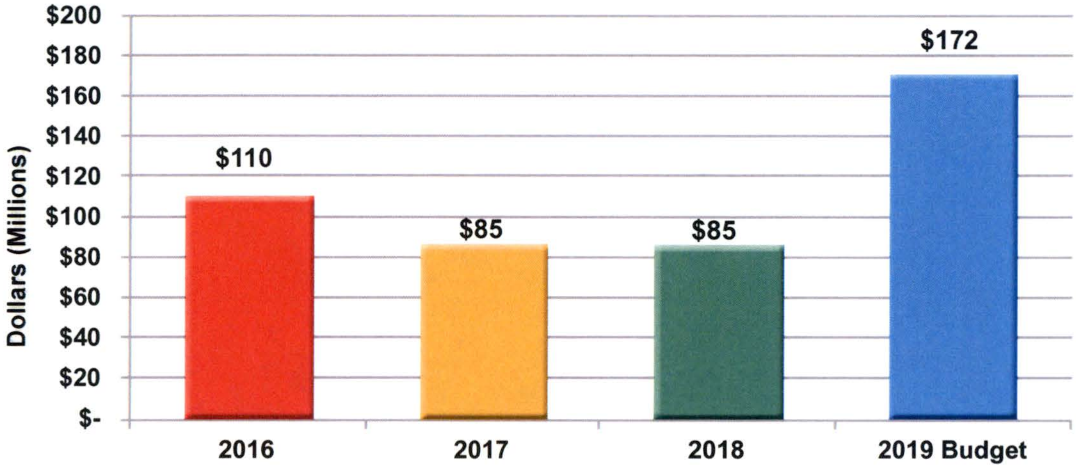
- $22.0 million for construction of a high-voltage transmission line from the Muddy Creek substation to Ord, Nebraska
- $16.4 million for construction of a high-voltage substation in Holt County, Nebraska and expansion of the GGS 345 kV substation
- $12.6 million for installation of stainless-steel liners in coal silos at GGS Units 1 and 2

There were other authorized capital projects for renewals and replacements to existing facilities and other additions and improvements of $43.0 million, $52.7 million, and $59.0 million for 2018, 2017, and 2016, respectively.

The Board-authorized budget for capital projects for 2019 is $172.0 million. Specific capital projects for 2019 include:

- $53.1 million amendment resulting in a new project cost of $417.0 million for the construction of a high-voltage transmission line approved in prior years
- $10.4 million to replace Two-Way Automatic Communication System meters
- $5.0 million for a reactor feeder pump turbine A overhaul at CNS

The following chart illustrates the Board-authorized capital projects for the years ended December 31, 2016 through 2018, including the Board-authorized budget for the year ended December 31, 2019.



RESOURCE PLANNING

The District uses a diverse mix of generation resources such as coal, nuclear, natural gas, hydro and wind to meet its firm requirement customer's needs. In 2018, the non-carbon energy resources as a percentage of native load sales were 56%. In 2017, a non-refueling year for the District's nuclear facility, the non-carbon energy resources as a percentage of native load sales were 65%.

The District's last comprehensive 20-year Integrated Resource Plan ("IRP") was completed and approved by the Board in 2013. There were several changes in assumptions that were included in the limited scope, five-year IRP approved by the Board at their March 2018 meeting. The 2018 IRP showed the District does not require new resources for the next five years. The changes in assumptions in the 2018 IRP included:

- 2016 Wholesale Power Contracts – The negotiation of new contracts with the District's wholesale customers, which extended the term 20 years for all but ten of the current customers. The new contract allows a 10% renewable self-supply option, or 2 MW, whichever is greater.

- Cooper Nuclear Station Power Uprate – The decision by the Board not to proceed with a power uprate at its nuclear facility, a low-cost resource option included in the 2013 IRP, due to a more detailed evaluation of costs and market risk.
- Renewable Energy – The addition of two new wind facilities of which 74 MW will be used to serve the District's firm customers. This brings the total amount of wind in the portfolio of resources serving firm customers to 281 MW.
- Sheldon Station – The recapture of approximately 65 MW of capacity and energy from Sheldon after the Board approved ending the participation sale for 30% of Sheldon's output to LES commencing in 2018.
- Southwest Power Pool Integrated Market – In 2014, SPP commenced a Day-Ahead, Ancillary Services, and Real-Time Balancing Market. The District, in turn, began participating as a member utility in the energy market place. The market coordinates next-day generation across its footprint to maximize cost effectiveness for its members. The District sells and purchases power in the SPP Integrated Market. A significant amount of renewables, primarily wind, continue to be added in the SPP Integrated Market.
- Hydrogen Purchase For Generation – Monolith Materials, Inc. ("Monolith") plans to construct and operate a carbon black facility adjacent to the District's Sheldon coal-fired generating facility in Nebraska. The construction of the carbon black facility is expected to be accomplished in two phases. The electric load to serve any Monolith facility will be served by Norris Public Power District, a firm wholesale customer of the District. At full buildout, Monolith may be the single-largest industrial customer served in the District's territory. The District entered into a 20-year contract with Monolith to purchase the carbon black plants' production of hydrogen rich gas, which will be produced by Monolith during production of carbon black. The District will have to convert its existing coal-fired boiler at Sheldon Unit No. 2 to burn the hydrogen rich gas. The boiler conversion is expected to result in a reduction of carbon dioxide ("CO_2"), sulfur dioxide ("SO_2"), mercury, and other air emissions. Groundbreaking for Phase 1 occurred in October 2016 and is expected to be mechanically complete in 2019 and fully operational in 2020. Phase 2 construction is planned to begin in the second half of 2022. The commercial operation date (defined jointly as the date on which Phase 2 is capable of sufficient, steady state hydrogen rich gas supply, and the Sheldon Unit No. 2 boiler has been converted and commissioned) is scheduled for 2024.

ENERGY 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 Risk Management ("ERM") program. The program originates with the Board-approved ERM Governing Policy and the ERM-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 ERM program. The objective of the ERM 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 ERM 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.

ECONOMIC FACTORS

Preliminary data indicate Nebraska's economy continued to experience growth in 2018 for the seventh consecutive year. The state's inflation adjusted, estimated gross state product ("GSP") increased by 0.3% from the second quarter of 2017 to the second quarter of 2018. The US economy experienced a 2.9% increase in national gross domestic product over the same, twelve-month period. Previous estimates of Nebraska's GSP were revised to reflect a small increase in GSP rather than the previously reported small decrease reported in the second and third quarters of 2016 to 2017. Substantial declines in Nebraska's "Agriculture, forestry, fishing, and hunting" and "Management of companies and enterprises," industries were offset by growth in "Manufacturing," "Retail trade," "Utilities," "Real estate and rental and leasing," "Construction," and "Information" industries.

Nebraska and the Midwest region continue to experience unemployment rates that are below the national average. Nebraska's average annual unemployment rate decreased from the revised 2016 value of 3.1% to 2.9% in 2017.This was well below the 2017 national average unemployment rate of 4.4%. Nebraska's preliminary, seasonally adjusted unemployment rate was 2.8% in December 2018, down from the revised 2.9% in December 2017. Both numbers were well below the national December seasonally adjusted unemployment rates of 3.9% in 2018 and 4.1% in 2017. Nebraska's preliminary December 2018 unemployment rate was the seventh lowest in the nation. The District continues to monitor changes in national and global economic conditions, as these could impact the cost of debt and access to capital markets.

CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

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:

- 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,
- "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, and
- issues relating to cyber and physical security.

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.

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Report of Independent Auditors

To the Board of Directors of the
Nebraska Public Power District:

We have audited the accompanying financial statements of Nebraska Public Power District (the "District"), which comprise the balance sheets as of December 31, 2018 and 2017, and the related statements of revenues, expenses, and changes in net position, and of cash flows for the years then ended.

Management's Responsibility 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; this includes 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.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the District's preparation and fair presentation of the financial statements 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, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the District as of December 31, 2018 and 2017 and, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States ofAmerica.

Other Matters

The accompanying management's discussion and analysis and the supplemental schedules on pages 5 through 19 and 56 through 59, respectively, are required by accounting principles generally accepted in the United States of America to supplement the basic financial statements. Such information, although not pwc

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

Our audits were conducted for the purpose of forming opinions on the financial statements that collectively comprise the District's basic financial statements. The statistical review is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has not been subjected to the auditing procedures applied in the audits of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

PricewaterhouseCoopers LLP

Chicago, Illinois
April 10, 2019

FINANCIAL STATEMENTS

Nebraska Public Power District

Balance Sheets as of December 31, (in 000's)

	2018	2017
ASSETS AND DEFERRED OUTFLOWS		
Current Assets:		
Cash and cash equivalents	$ 25,502	$ 27,804
Investments	616,685	539,173
Receivables, less allowance for doubtful accounts of $608 and $541, respectively	133,736	120,254
Fossil fuels, at average cost	19,545	43,264
Materials and supplies, at average cost	113,297	111,644
Prepayments and other current assets	15,343	16,733
	924,108	858,872
Special Purpose Funds:		
Construction funds	38,012	54,808
Debt reserve funds	86,924	88,764
Employee benefit funds	2,300	1,934
Decommissioning funds	600,371	600,942
	727,607	746,448
Utility Plant, at Cost:		
Utility plant in service	5,015,458	4,928,370
Less reserve for depreciation	2,756,094	2,658,206
	2,259,364	2,270,164
Construction work in progress	125,237	133,515
Nuclear fuel, at amortized cost	177,955	166,219
	2,562,556	2,569,898
Other Long-Term Assets:		
Regulatory asset for other postemployment benefits	185,451	210,362
Long-term capacity contracts	146,004	152,831
Unamortized financing costs	7,651	8,201
Investment in The Energy Authority	7,006	6,175
Other	4,934	6,132
	351,046	383,701
Total Assets	4,565,317	4,558,919
Deferred Outflows of Resources:		
Asset retirement obligation	238,086	222,369
Unamortized cost of refunded debt	34,039	38,430
Other postemployment benefits	61,218	34,603
	333,343	295,402
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,898,660	$ 4,854,321
LIABILITIES, DEFERRED INFLOWS, AND NET POSITION		
Current Liabilities:		
Revenue bonds, current	$ 78,935	$ 98,205
Revolving credit agreements and notes, current	199,964	165,212
Accounts payable and accrued liabilities	58,093	64,981
Accrued in lieu of tax payments	10,312	10,000
Accrued payments to retail communities	5,281	6,074
Accrued compensated absences	18,208	16,971
Other	9,882	9,058
	380,675	370,501
Long-Term Debt:		
Revenue bonds, net of current	1,451,605	1,548,269
Revolving credit agreements and notes, net of current	55,000	69,000
	1,506,605	1,617,269
Other Long-Term Liabilities:		
Asset retirement obligation	839,510	823,794
Net other postemployment benefit liability	141,923	182,835
Other	15,926	21,838
	997,359	1,028,467
Total Liabilities	2,884,639	3,016,237
Deferred Inflows of Resources:		
Unearned revenues	247,853	206,927
Other deferred inflows	197,027	144,724
	444,880	351,651
Net Position:		
Net investment in capital assets	1,075,361	1,029,230
Restricted	36,026	37,782
Unrestricted	457,754	419,421
	1,569,141	1,486,433
TOTAL LIABILITIES, DEFERRED INFLOWS, AND NET POSITION	$ 4,898,660	$ 4,854,321

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

Nebraska Public Power District
Statements of Revenues, Expenses, and Changes in Net Position

For the years ended December 31, (in 000's)	2018	2017
Operating Revenues	$ 1,144,858	$ 1,101,642
Operating Expenses:		
Power purchased	161,665	161,963
Production:		
Fuel	174,711	180,858
Operation and maintenance	274,979	243,332
Transmission and distribution operation and maintenance	105,198	100,945
Customer service and information	16,805	15,988
Administrative and general	104,916	106,190
Payments to retail communities	27,745	27,102
Decommissioning	15,755	19,934
Depreciation and amortization	133,057	122,559
Payments in lieu of taxes	10,354	10,060
	1,025,185	988,931
Operating Income	119,673	112,711
Investment and Other Income:		
Investment income	23,381	20,091
Other income	3,515	3,500
	26,896	23,591
Increase in Net Position Before Debt and Other Expenses	146,569	136,302
Debt and Related Expenses:		
Interest on revenue bonds	72,198	76,186
Allowance for funds used during construction	(2,318)	(2,317)
Bond premium amortization net of debt issuance expense	(12,014)	(12,598)
Interest on revolving credit agreements and notes	5,995	3,715
	63,861	64,986
Increase in Net Position	82,708	71,316
Net Position:		
Beginning balance	1,486,433	1,415,117
Ending balance	$ 1,569,141	$ 1,486,433

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

Nebraska Public Power District
Statements of Cash Flows

For the years ended December 31, (in 000's)	2018	2017
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 1,135,762	$ 1,112,281
Other receipts	195	679
Payments to suppliers and vendors	(521,872)	(503,685)
Payments to employees	(250,997)	(244,178)
Net cash provided by operating activities	363,088	365,097
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	3,189,635	2,792,011
Purchases of investments	(3,253,986)	(2,920,411)
Income received on investments	18,467	20,962
Net cash used in investing activities	(45,884)	(107,438)
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of revenue bonds	-	96,957
Proceeds from revolving credit agreements and notes	70,195	98,737
Capital expenditures for utility plant	(172,953)	(140,665)
Contributions in aid of construction and other reimbursements	7,093	9,062
Principal payments on revenue bonds	(98,590)	(191,160)
Interest payments on revenue bonds	(72,198)	(76,920)
Interest paid on defeased revenue bonds	-	(1,107)
Principal payments on revolving credit agreements and notes	(49,443)	(127,449)
Interest payments on revolving credit agreements and notes	(5,600)	(3,554)
Other non-operating revenues	1,990	3,515
Net cash used in capital and related financing activities	(319,506)	(332,584)
Net decrease in cash and cash equivalents	(2,302)	(74,925)
Cash and cash equivalents, beginning of year	27,804	102,729
Cash and cash equivalents, end of year	$ 25,502	$ 27,804
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 119,673	$ 112,711
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation and amortization	133,057	122,559
Undistributed net revenue - The Energy Authority	106	108
Decommissioning, net of customer contributions	9,624	14,006
Amortization of nuclear fuel	36,177	43,490
Changes in assets and liabilities which (used) provided cash:		
Receivables, net	823	5,409
Fossil fuels	23,719	356
Materials and supplies	(1,653)	2,996
Prepayments and other current assets	1,557	443
Other long-term assets	986	938
Deferred outflows	(23,500)	-
Accounts payable and accrued payments to retail communities	(4,559)	(11,275)
Unearned revenues	40,926	38,217
Other deferred inflows	24,176	33,404
Other liabilities	1,976	1,735
Net cash provided by operating activities	$ 363,088	$ 365,097
Supplementary Non-Cash Capital Activities:		
Change in utility plant additions in accounts payable	$ (3,511)	$ (10,768)

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 balance sheet, 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 balance sheet.

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 2.3% for the years ended December 31, 2018 and 2017. The District had fully depreciated utility plant, primarily related to Cooper Nuclear Station ("CNS"), which was still in service of $992.2 million and $978.1 million as of December 31, 2018 and 2017, respectively.

The District has long-term Professional Retail Operations ("PRO") Agreements with 79 municipalities for certain retail electric distribution systems. 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 $14.8 million and $7.5 million in 2018 and 2017, respectively, which was included in depreciation and amortization expense. The increase in amortization from 2017 to 2018 was primarily due to the advanced metering infrastructure project. These utility plant additions, which were fully amortized, totaled $205.7 million and $191.8 million as of December 31, 2018 and 2017, 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 tax-exempt commercial paper ("TECP"), tax-exempt revolving credit agreement ("TERCA"), or taxable revolving credit agreement ("TRCA") is charged a rate based upon the projected average interest cost of the related debt outstanding. The TECP program was terminated in 2017 and replaced with the TERCA. For the periods presented herein, the AFUDC rates for construction funded by revenue bonds varied from 2.2% to 4.9%. For construction financed on a short-term basis, the rate was 2.3% for 2018 and 1.0% for 2017.

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* –
Asset retirement obligations ("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 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 and an international equity fund, which are reported at net asset value.

L. *Auction Revenue Rights and Transmission Congestion Rights* –
The District uses Auction Revenue Rights ("ARR") and Transmission Congestion Rights ("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 balance sheet 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 cost of refunded debt is the difference in the reacquisition price and the net carrying amount of the refunded debt in an advance refunding. 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, CNS 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 ("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 taken into account 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, 2018 and 2017 and activity for the years then ended (in 000's):

	2018	2017
Unearned revenues, beginning of year	$ 206,927	$ 168,710
Surpluses	70,006	44,888
Use of prior period rate stabilization funds in rates	(29,080)	(6,671)
Unearned revenues, end of year	$ 247,853	$ 206,927

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 CNS. Details of the District's DOE settlements are included in Note 12 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 CNS 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 in the Notes to Financial Statements.

Beginning in 2017, the District began collecting revenues for the costs of the 2018 CNS refueling and maintenance outage. This regulatory liability was included in Other deferred inflows on the Balance Sheets and was amortized through revenue during 2018, 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 Lincoln Electric System ("LES") 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 Balance Sheets and will be eliminated as the revenues from the settlement payments are incorporated in future rates.

The District began collecting in rates for non-nuclear decommissioning costs in 2017. The collections for assets which do not have a legally required retirement obligation are recorded as a regulatory liability, instead of an ARO, and are included, along with the interest on these funds, in Other deferred inflows on the Balance Sheets.

The following table summarizes the balance of Deferred outflows of resources as of December 31, 2018 and 2017 (in 000's):

	2018	2017
Asset retirement obligation	$ 238,086	$ 222,369
Unamortized cost of refunded debt	34,039	38,430
Unrealized OPEB contributions and losses	61,218	34,603
	$ 333,343	$ 295,402

The following table summarizes the balance of Other deferred inflows of resources as of December 31, 2018 and 2017 (in 000's):

	2018	2017
DOE settlements	$ 75,401	$ 66,227
Nuclear fuel disposal collections	26,800	21,570
CNS outage collections	-	20,005
Settlements for termination of agreements	44,007	10,500
Unrealized OPEB gains	35,592	16,475
Non-nuclear decommissioning collections	11,007	5,444
Renewable energy facility sales tax refund	4,220	4,503
	$ 197,027	$ 144,724

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 notes 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 notes attributable to these assets.

Restricted net position consisted of the Primary account in the Debt reserve funds that are required deposits under the 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 non-nuclear 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. 89, *Accounting for Interest Cost Incurred Before the End of a Construction Period,* was issued in June 2018. This Statement will require that interest cost incurred before the end of a construction period be recognized as an expense in the period in which the cost is incurred instead of as an addition to the cost of the utility plant asset. The requirements of this Statement are effective for reporting periods beginning after December 15, 2019. Management is currently evaluating the impact of this Statement.

GASB Statement No. 88, *Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements,* was issued in April 2018. This Statement will require additional disclosures in the notes related to debt such as terms related to significant events of default with finance-related consequences and significant subjective acceleration clauses. The requirements of this Statement are effective for reporting periods beginning after June 15, 2018. This Statement will be implemented by the District in 2019.

GASB Statement No. 87, *Leases,* was issued in June 2017. This Statement will bring substantially all leases for lessees on to the balance sheet. For operating leases, lessees will be required to recognize an asset for the right to use the leased item and a corresponding lease liability. Lease liabilities will be considered long-term debt and lease payments will be capital financing outflows in the cash flow statement. In the activity statement, lessees will no longer report rent expense for 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. The requirements of this Statement are effective for reporting periods beginning after December 15, 2019. Management is currently evaluating the impact of this statement.

GASB Statement No. 85, *Omnibus 2017,* was issued in March 2017. This Statement addresses practice issues that were identified during implementation and application of certain GASB statements including statements on OPEB.

This Statement provides clarification for the presentation of payroll-related measures in required supplementary information for purposes of reporting by OPEB plans and employers that provide OPEB. This Statement requires the disclosure of covered-employee payroll by the employer if contributions to the OPEB plan are not based on a measure of pay. Covered-employee payroll is defined as the payroll of employees that are provided with OPEB through the OPEB plan. However, the financial statements for the OPEB plan should not present any measure of payroll if contributions to the plan are not based on a measure of pay. This Statement is effective for fiscal years beginning after June 15, 2017. The District adopted this Statement in 2017 to coincide with its implementation of related guidance in GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions.* The OPEB guidance was the only portion of this Statement with an impact on the District.

GASB Statement No. 84, *Fiduciary Activities,* was issued in January 2017. This Statement addresses accounting and financial reporting requirements for certain fiduciary funds in the basic financial statements. Governments with activities meeting the criteria are required to present a statement of fiduciary net position and a statement of changes in fiduciary net position. The requirements of this Statement are effective for reporting periods beginning after December 15, 2018. The implementation of this Statement will require the District to include fiduciary statements with the statements for its business-type activities. This Statement will be implemented by the District in 2019.

GASB Statement No. 83, *Certain Asset Retirement Obligations,* was issued in November 2016. This Statement addresses accounting and financial reporting requirements for certain AROs. This Statement imposes requirements in regard to the ARO liability recognition, measurement and specifics on when re-measurement should occur. This Statement also requires disclosures regarding the methods and assumptions used to estimate the ARO, the remaining useful life of capital assets associated with the liability, any governmental legal funding requirements, any assets restricted for payment and any minority share ARO liability. The requirements of this Statement are effective for reporting periods beginning after June 15, 2018. The District previously reported AROs under the FASB guidance, which differs from the GASB guidance. The FASB guidance required measurement of the liability based on the present value of the asset's disposal costs whereas measurement under this GASB Statement is based on the best estimate of the current value of cash outlays expected to be incurred. The FASB guidance required the recognition of a corresponding capital asset whereas the GASB Statement requires the recognition of a corresponding deferred outflow of resources. The District adopted this Statement in 2017 and uses regulatory accounting to align asset retirement costs with their related recognition in rates.

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 $0.2 million and a net gain of $2.6 million in 2018 and 2017, respectively.

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

	2018		2017	
	Fair Value	Weighted Average Maturity (Years)	Fair Value	Weighted Average Maturity (Years)
U.S. Treasury and government agency securities	$1,041,504	5.1	$ 998,148	4.7
Corporate bonds	170,763	8.9	169,051	9.3
Municipal bonds	9,262	12.6	11,900	14.3
Cash and cash equivalents	148,265	0.1	134,326	0.1
Total cash and investments	$1,369,794		$1,313,425	
Portfolio weighted average maturity		5.1		4.9

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 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 balance sheet, except cash and cash equivalents in the Revenue Fund investment account are reported as investments. The investment account for the Revenue funds included cash equivalents of $106.0 million and $99.5 million as of December 31, 2018 and 2017, respectively.

	2018	2017
Revenue funds - Cash and cash equivalents	$ 131,472	$ 127,302
Revenue funds - Investments	510,715	439,675
	$ 642,187	$ 566,977

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 revenue bond proceeds and the issuance of short-term debt.

	2018	2017
Construction funds - Investments	$ 38,012	$ 54,808

The Debt reserve funds, as established under the Resolution, consist of a Primary account and a Secondary account. The District is required by the 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 $36.0 million and $37.8 million as of December 31, 2018 and 2017, 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 $50.9 million and $51.0 million as of December 31, 2018 and 2017, respectively.

	2018	2017
Debt reserve funds - Investments	$ 86,924	$ 88,764

The Employee Benefit funds consist of a self-funded hospital-medical benefit plan for active employees only as of December 31, 2018 and 2017. The District pays 80% of the hospital-medical premiums with the employees paying the remaining 20% of the cost of such coverage.

	2018	2017
Employee benefit funds - Cash and cash equivalents	$ 2,054	$ 935
Employee benefit funds - Investments	247	999
	$ 2,301	$ 1,934

The Decommissioning funds are utilized to account for the investments held to fund the estimated cost of decommissioning CNS 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.

	2018	2017
Decommissioning funds - Cash and cash equivalents	$ 14,739	$ 6,089
Decommissioning funds - Investments	585,632	594,853
	$ 600,371	$ 600,942

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 Statement No. 72 ("GASB 72"), *Fair Value Measurement and Application*, establishes 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 in GASB 72 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 72. 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 72 as of December 31, 2018 and 2017.

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):

	2018			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 635,897	$ -	$ 635,897
Cash and cash equivalents	133,526	-	-	133,526
Decommissioning funds:				
U.S. Treasury and government agency securities	-	405,607	-	405,607
Corporate bonds	-	170,763	-	170,763
Municipal bonds	-	9,262	-	9,262
Cash and cash equivalents	14,739	-	-	14,739
	$ 148,265	$1,221,529	$ -	$1,369,794

	2017			
	Level 1	Level 2	Level 3	Total
Revenue and special purpose funds, excluding decommissioning:				
U.S. Treasury and government agency securities	$ -	$ 584,246	$ -	$ 584,246
Cash and cash equivalents	128,237	-	-	128,237
Decommissioning funds:				
U.S. Treasury and government agency securities	-	413,902	-	413,902
Corporate bonds	-	169,051	-	169,051
Municipal bonds	-	11,900	-	11,900
Cash and cash equivalents	6,089	-	-	6,089
	$ 134,326	$1,179,099	$ -	$1,313,425

4. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2018, was as follows (in 000's):

	December 31, 2017	Increases	Decreases	December 31, 2018
Nondepreciable utility plant:				
Land and improvements	$ 75,194	$ 1,250	$ (1,104)	$ 75,340
Construction in progress	133,515	95,938	(104,216)	125,237
Total nondepreciable utility plant	208,709	97,188	(105,320)	200,577
Nuclear fuel*	166,219	47,913	(36,177)	177,955
Depreciable utility plant:				
Generation - Fossil	1,650,157	8,348	(1,140)	1,657,365
Generation - Nuclear	1,322,006	25,244	(8,470)	1,338,780
Transmission	1,296,633	54,418	(3,945)	1,347,106
Distribution	234,445	17,362	(3,691)	248,116
General	349,935	9,749	(10,933)	348,751
Total depreciable utility plant	4,853,176	115,121	(28,179)	4,940,118
Less reserve for depreciation	(2,658,206)	(126,067)	28,179	(2,756,094)
Depreciable utility plant, net	2,194,970	(10,946)	-	2,184,024
Utility plant activity, net	$ 2,569,898	$ 134,155	$ (141,497)	$ 2,562,556

* Nuclear fuel decreases represented amortization of $36.2 million.

Utility plant activity for the year ended December 31, 2017, was as follows (in 000's):

	December 31, 2016	Increases	Decreases	December 31, 2017
Nondepreciable utility plant:				
Land and improvements	$ 74,138	$ 1,124	$ (68)	$ 75,194
Construction in progress	135,853	120,399	(122,737)	133,515
Total nondepreciable utility plant	209,991	121,523	(122,805)	208,709
Nuclear fuel*	197,730	11,979	(43,490)	166,219
Depreciable utility plant:				
Generation - Fossil	1,621,919	33,992	(5,754)	1,650,157
Generation - Nuclear	1,314,210	14,978	(7,182)	1,322,006
Transmission	1,254,421	47,223	(5,011)	1,296,633
Distribution	226,563	9,291	(1,409)	234,445
General	344,578	15,169	(9,812)	349,935
Total depreciable utility plant	4,761,691	120,653	(29,168)	4,853,176
Less reserve for depreciation	(2,573,645)	(113,729)	29,168	(2,658,206)
Depreciable utility plant, net	2,188,046	6,924	-	2,194,970
Utility plant activity, net	$ 2,595,767	$ 140,426	$ (166,295)	$ 2,569,898

* Nuclear fuel decreases represented amortization of $43.5 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 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 $44.3 million and $39.9 million as of December 31, 2018 and 2017, respectively. The unamortized amount of the plant capacity contract was $134.7 million and $139.2 million as of December 31, 2018 and 2017, respectively, of which $4.4 million was included in Prepayments and other current assets as of December 31, 2018 and 2017. The District's share of NC2 working capital was also included in Prepayments and other current assets and was $6.6 million and $6.5 million as of December 31, 2018 and 2017, 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 is amortizing the contract on a straight-line basis over the 40-year estimated useful life of the facility. Accumulated amortization was $68.9 million and $66.6 million as of December 31, 2018 and 2017, respectively. The unamortized amount of the Central capacity contract was $17.8 million and $20.1 million as of December 31, 2018 and 2017, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2018 and 2017.

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. Costs of $1.4 million and $1.8 million in 2018 and 2017, respectively, are included in Power purchased in the accompanying Statements of Revenues, Expenses, and Changes in Net Position.

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% and 16.67% as of December 31, 2018 and 2017, respectively. In addition to the District, the following utilities have interests of 17.65% each as of December 31, 2018: 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, 2018: City Utilities of Springfield, Missouri and Gainesville Regional Utilities (Florida). Cowlitz County Public Utility District (Washington) terminated its ownership interest in TEA in 2018.

Such investment was $7.0 million and $6.2 million as of December 31, 2018 and 2017, 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.

The District is obligated to guaranty, directly or indirectly, TEA's electric trading activities in an amount up to $78.9 million plus attorney's fees 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 guaranties would be equalized ratably, based upon each member's interest in TEA and the guarantees they have provided. The District increased its guarantee to TEA in March 2018 from $28.9 million to $78.9 million. The additional $50.0 million of guaranty is to support additional trading for TEA on behalf of its continued business growth. After such contributions have been made, the District would only have recourse against TEA to recover amounts paid under the guaranty. The term of this guaranty is generally indefinite, but the District may terminate its guaranty obligations by providing advanced notice to the beneficiaries thereof. Such termination of its guaranty 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, 2018 and 2017.

Financial statements for TEA may be obtained at The Energy Authority, 301 W. Bay Street, Suite 2600, Jacksonville, Florida, 32202.

7. DEBT:

The following table summarizes debt balances as of December 31, 2018 and 2017, and debt activity for 2018 (in 000's):

	Total Debt at December 31, 2017	Increases	Decreases	Total Debt at December 31, 2018	Long-Term Debt at December 31, 2018	Current Liabilities at December 31, 2018
Revenue bonds	$ 1,646,474	$ -	$ (115,934)	$ 1,530,540	$ 1,451,605	$ 78,935
Revolving credit agreements	234,212	70,195	(49,443)	254,964	55,000	199,964
Total debt activity	$ 1,880,686	$ 70,195	$ (165,377)	$ 1,785,504	$ 1,506,605	$ 278,899

The following table summarizes debt balances as of December 31, 2017 and 2016, and debt activity for 2017 (in 000's):

	Total Debt at December 31, 2016	Increases	Decreases	Total Debt at December 31, 2017	Long-Term Debt at December 31, 2017	Current Liabilities at December 31, 2017
Revenue bonds	$ 1,760,094	$ 96,957	$ (210,577)	$ 1,646,474	$ 1,548,269	$ 98,205
Commercial paper notes	74,000	11,320	(85,320)	-	-	-
Revolving credit agreements	188,924	87,417	(42,129)	234,212	69,000	165,212
Total debt activity	$ 2,023,018	$ 195,694	$ (338,026)	$ 1,880,686	$ 1,617,269	$ 263,417

Revenue Bonds

In January 2019, the District issued $36.0 million of General Revenue Bonds, 2019 Series A, at a premium of $5.2 million, to refund $50.4 million of General Revenue Bonds, 2009 Series A (Taxable Build America Bonds). The refunding was completed with $41.2 million of the proceeds from General Revenue Bonds, 2019 Series A, $3.7 million from the TERCA, and $5.5 million of other available funds. As a result, total debt service payments over the life of the bonds was reduced by $20.4 million, which resulted in present value savings of $6.6 million.

In January 2019, the District defeased certain of the General Revenue Bonds, 2017 Series A, with an outstanding principal amount that aggregated $7.3 million.

In January 2019, the District called the remaining outstanding General Revenue Bonds, 2009 Series C, with a principal amount that aggregated $0.4 million.

The District expects to issue additional revenue bonds in 2019 for an SPP Notice to Construct project for 225 miles of 345 kV transmission line, budgeted at $417.0 million, which project may be financed in whole or in part, beginning in 2019 and throughout its scheduled completion in 2021.

In January 2018, the District called the remaining outstanding General Revenue Bonds, 2012 Series C, with a principal amount that aggregated $4.2 million.

In April 2017, the District issued General Revenue Bonds, 2017 Series A and 2017 Series B, in the amount of $86.0 million to refund the General Revenue Bonds, 2007 Series B. The refunding reduced total debt service payments over the life of the bonds by $11.8 million, which resulted in present value savings of $10.0 million.

Congressional action reduced the 35% interest subsidy, pursuant to the requirements of the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, on the District's General Revenue Bonds, 2009 Series A (Taxable Build America Bonds) and 2010 Series A (Taxable Build America Bonds). Reductions were 6.6% and 6.9% for fiscal years ended September 30, 2018 and 2017, respectively.

There were no outstanding principal amounts from legal defeasances of General Revenue Bonds as of December 31, 2018. There were outstanding principal amounts aggregating $324.1 million from legal defeasances of General Revenue Bonds, 2008 Series B and 2012 Series C, as of December 31, 2017.

Debt service payments and principal payments of the General Revenue Bonds as of December 31, 2018, are as follows (in 000's):

Year	Debt Service Payments	Principal Payments
2019	$ 146,856	$ 78,935
2020	146,760	82,915
2021	143,968	84,085
2022	136,550	80,825
2023	136,152	83,920
2024-2028	611,677	411,375
2029-2033	443,737	332,750
2034-2038	216,152	175,000
2039-2043	83,628	73,130
2044-2045	5,615	5,220
Total Payments	$ 2,071,095	$ 1,408,155

The fair value of outstanding revenue bonds was determined using currently published rates. The fair value was estimated to be $1,610.4 million and $1,737.9 million as of December 31, 2018 and 2017, respectively.

Commercial Paper Notes and Line of Credit Agreement

The District terminated its Commercial Paper Notes ("Notes") program and the Line of Credit Agreement that supported the payment of the principal outstanding on the Notes after execution of the TERCA in 2017.

Tax-Exempt Revolving Credit Agreement

The District entered into a TERCA with two commercial banks to provide for loan commitments to the District up to an aggregate amount not to exceed $150.0 million on June 29, 2017. The TERCA replaced the Commercial Paper Notes and Line of Credit Agreement. The District had an outstanding balance under the TERCA of $55.0 million and $69.0 million as of December 31, 2018 and 2017, 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 because the agreement terminates on June 29, 2020.

Taxable Revolving Credit Agreement

The District has 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 $200.0 million and $165.2 million, as of December 31, 2018 and 2017, respectively. The outstanding amount is anticipated to be retired by future collections through electric rates. The carrying value approximates market value because the agreement was renewed on July 30, 2018, with a termination date of July 29, 2021.

Revenue bonds consist of the following (000's except interest rates):

December 31,	Interest Rate	2018	2017
General Revenue Bonds:			
2009 Series A Taxable Build America Bonds:			
Term Bonds: 2019–2025	6.606%	$17,465	$17,465
2026–2034	7.399%	32,890	32,890
2009 Series C Serial Bonds 2017–2019	4.00% - 4.25%	-	2,535
2010 Series A Taxable Build America Bonds:			
Serial Bonds: 2019–2024	3.98% - 4.73%	31,875	31,875
Term Bonds: 2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2010 Series B Taxable Serial Bonds 2016–2020	3.73% - 4.18%	1,880	2,755
2010 Series C:			
Serial Bonds: 2017–2025	3.00% - 5.00%	32,190	40,685
Term Bonds: 2026–2030	4.00%	6,165	6,165
2026–2030	5.00%	14,180	14,180
2012 Series A Serial Bonds 2017–2034	3.00% - 5.00%	173,490	182,145
2012 Series B:			
Serial Bonds: 2017–2032	2.00% - 5.00%	74,410	83,330
Term Bonds: 2033–2036	3.625%	2,320	2,320
2037–2042	3.625%	4,155	4,155
2013 Series A Serial Bonds 2017–2033	3.00% - 5.00%	62,680	77,480
2014 Series A:			
Serial Bonds: 2017–2038	2.00% - 5.00%	147,135	151,015
Term Bonds: 2039–2043	4.00%	31,650	31,650
2039–2043	4.125%	1,945	1,945
2014 Series C Serial Bonds 2017–2033	4.00% - 5.00%	115,685	138,130
2015 Series A-1 Serial Bonds 2022–2034	3.00% - 5.00%	119,400	119,400
2015 Series A-2:			
Serial Bonds: 2017–2034	3.00% - 5.00%	55,590	56,045
Term Bonds: 2035–2039	5.00%	46,205	46,205
2016 Series A:			
Serial Bonds: 2018–2035	3.125% - 5.00%	53,665	65,210
Term Bonds: 2036–2040	5.00%	5,595	5,595
2016 Series B:			
Serial Bonds: 2018–2036	5.00%	64,570	67,255
Term Bonds: 2037–2039	5.00%	1,165	1,165
2016 Series C Serial Bonds 2017–2035	3.00% - 5.00%	63,245	67,025
2016 Series D:			
Serial Bonds: 2017–2035	2.00% - 5.00%	20,135	20,960
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%	56,050	56,050
2017 Series A Serial Bonds 2017–2027	2.00% - 5.00%	15,360	18,125
2017 Series B Serial Bonds 2017–2027	5.00%	53,240	59,170
Total par amount of revenue bonds		1,408,155	1,506,745
Unamortized premium net of discount		122,385	139,729
		1,530,540	1,646,474
Less – current maturities of revenue bonds		(78,935)	(98,205)
Total revenue bonds		$1,451,605	$1,548,269

8. PAYMENTS IN LIEU OF TAXES:

The District is required to make payments in lieu of taxes, aggregating 5% 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 $10.4 million and $10.1 for the years ended December 31, 2018 and 2017, respectively.

9. ASSET RETIREMENT OBLIGATIONS:

The District implemented GASB Statement No. 83, *Certain Asset Retirement Obligations,* in 2017, retroactive to 2016. Prior to the implementation of the GASB guidance, FASB guidance had been used for ARO reporting. The FASB guidance required measurement of the liability based on discounted dollars or the present value of the asset's disposal costs. Measurement 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 FASB guidance required the recognition of a corresponding capital asset whereas 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	2018	2017
CNS license termination costs	$ 827,307	$ 811,801
GGS and Sheldon ash landfills	9,212	9,040
Ainsworth	1,991	1,953
Underground storage tanks	1,000	1,000
	$ 839,510	$ 823,794

The District is required by the Nuclear Regulatory Commission ("NRC") to decommission CNS after cessation of plant operations, consistent with regulations in the U.S. Code of Federal Regulations. The CNS 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 2015 dollars. The inflation rates used were 1.91% and 2.11% for the years 2018 and 2017, respectively. The District has funds set aside for decommissioning of $600.4 million and $600.9 million as of December 31, 2018 and 2017, 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 Quality ("NDEQ") to decommission the ash landfills at Gerald Gentleman Station ("GGS") and Sheldon, consistent with their regulations. As GASB guidance is unclear related to the accounting treatment for ash landfill AROs, GASB Statement No. 83 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 GGS and Sheldon, 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 2017 dollars. The rate in the CPI-U was used to adjust these obligations for inflation. The inflation rate used was 1.91% for the year 2018. The District provided guarantees and financial assurance through correspondence and supporting information to NDEQ in 2018. Commencing in 2017, the District included in rates decommissioning costs for certain assets at GGS and Sheldon. The costs included in rates for the decommissioning of the ash landfills were $0.4 million for 2018 and 2017. 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 ("Ainsworth") 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 has an estimated closure date of September 30, 2025. The ARO was based on an external study for costs using one scenario. The assumptions included: 1) no hazardous construction material abatement is required; 2) no environmental costs to address site clean-up; 3) floor drain and septic tanks will be decommissioned per state regulations; 4) wind turbine nacelles, turbine towers, transformers and other electrical equipment are removed from the site by the demolition contractor; 5) the O&M buildings and one onsite meteorological tower were included with the demolition costs; 6) all foundations will be removed to two feet below finished grade; and 7) all concrete and crushed rock surfacing will be removed. The costs in the study were in 2015 dollars. Rates in the CPI-U were used to adjust these obligations for inflation. The inflation rates used were 1.91% and 2.11% for the years 2018 and 2017, respectively. There are no legally required funding and assurance provisions associated with this ARO. The costs included in rates for the decommissioning of Ainsworth were $0.2 million and $0.1 million for 2018 and 2017, respectively. These rate collections reduced the related deferred outflow for Ainsworth.

The District is required by the NDEQ 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 NDEQ in 2018. There have not been any decommissioning costs for the underground storage tanks included in rates.

10. RETIREMENT PLAN:

The District's Employees' Retirement Plan (the "Plan") is a defined contribution 401(k) pension plan established and administered by the District to provide benefits at retirement to regular full-time and part-time employees. There were 1,888 and 1,848 active Plan members as of December 31, 2018 and 2017, 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. Beginning January 1, 2018, the Board approved an increase in matching for covered salary from $40,000 to $75,000. Contributions ranging from 2% to 5% 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 covered salary up to $75,000. On covered salary greater than $75,000, the District contributes one times the Plan member's contribution. The Participants' contributions were $14.6 million and $13.7 million for 2018 and 2017, respectively. The District's matching contributions were $14.8 million and $12.0 million for 2018 and 2017, respectively. Total contributions of $1.5 million and $1.3 million were accrued in Accounts payable and accrued liabilities as of December 31, 2018 and 2017, respectively.

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 a defined contribution 457 pension plan ("457 Plan"). The 457 Plan is a tax-deferred investment option with no District match. Pay period contributions can be elected and changed at any time. Early withdrawals can be made from the 457 Plan following separation of service regardless of age with no IRS penalty. Income taxes are owed on any withdrawals. The Participants' contributions were $2.2 million and $2.5 million for 2018 and 2017, respectively.

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 on long-term disability and their 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. The District pays all or part of the cost (determined by age) of certain hospital-medical premiums for employees hired on or prior to December 31, 1992. Employees hired on or after January 1, 1993, are subject to a contribution cap that limits the District's portion of the cost of such coverage to the full premium the year the employee reached age 65, or the year in which the employee retires if older than age 65. Employees hired on or after January 1, 1999, are not eligible for other postemployment hospital-medical benefits once they reach age 65. Employees hired on or after January 1, 2004, are not eligible for other postemployment hospital-medical benefits once they retire. The District amended the Plan effective July 1, 2007, to provide that any former employee who is rehired will receive credit for prior years of service. The District further amended the Plan effective September 1, 2007, to provide that employees hired or rehired on or after that date must work five consecutive years immediately prior to retirement to be eligible for other postemployment hospital-medical benefits once they retire. In May 2015, the Board approved a change for Medicare-eligible retirees for prescription drugs from the District's self-insured employee prescription plan to a group insured Medicare Part D supplement effective January 1, 2016. The District also provides a postemployment death benefit of $5,000 for qualifying employees.

Employees Covered by Benefit Terms

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

	2018	2017
Active employees	971	1,007
Inactive employees in retirement status	1,361	1,381
Inactive employees in long-term disability status	61	64
Total employees covered by benefit terms	2,393	2,452

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

	2018	2017
Active employees	1,838	1,851
Inactive employees in retirement status	1,185	1,213
Inactive employees in long-term disability status	70	72
Total employees covered by benefit terms	3,093	3,136

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 $56.7 million and $28.4 million in 2018 and 2017, respectively. The 2018 contributions were higher due to additional contributions for service for prior years. Certain wholesale customers under the 2002 Contracts objected to the inclusion in rates of additional collections of previously incurred OPEB costs. An arbitration panel ruled in favor of the District in April 2017. This case was appealed and argued before the Nebraska Supreme Court in March 2018. The Court upheld the 2017 arbitration decision in June 2018. Information on litigation with wholesale customers under the 2002 Contracts is included in Note 12.C.

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 $0.7 million and $0.6 million for 2018 and 2017, respectively. 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 Liability –*
The District's net OPEB liability was measured as of January 1, 2018, and January 1, 2017, and the total OPEB liability used to calculate the net OPEB liability was determined by an actuarial valuation as of these dates.

Actuarial Assumptions
The actuarial assumptions used in the January 1, 2018 actuarial valuation were based on the results of an actuarial experience study for the period January 1, 2017 through December 31, 2017. The total OPEB liability in the January 1, 2018, actuarial valuation was determined using the following actuarial assumptions, applied to all periods included in the measurement, unless otherwise specified:

Discount rate	6.25%
Healthcare cost trend rates	Pre-Medicare: 7.7% initial, ultimate 4.5%
	Post-Medicare: 8.7% initial, ultimate 4.5%
Inflation	2.3%
Salary increase	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2017 with generational projection
Retirement Age	Varies by age

The actuarial assumptions used in the January 1, 2017, actuarial valuation were based on the results of an actuarial experience study for the period January 1, 2016 through December 31, 2016. The total OPEB liability in the January 1, 2017, actuarial valuation was determined using the following actuarial assumptions, applied to all periods included in the measurement, unless otherwise specified:

Discount rate	6.25%
Healthcare cost trend rates	Pre-Medicare: 7.3% initial, ultimate 4.5%
	Post-Medicare: 9.1% initial, ultimate 4.5%
Inflation	2.1%
Salary increase	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2016 with generational projection
Retirement Age	Varies by age

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,:

Asset Class	Target Allocation	2018 Long-Term Expected Real Rate of Return
Equity (1)	70%	6.8%
Fixed income	30%	3.3%
	100%	6.0%

Asset Class	Target Allocation	2017 Long-Term Expected Real Rate of Return
Equity (1)	70%	6.8%
Fixed Income	30%	3.6%
	100%	6.1%

(1) The actuary included the 10% real estate allocation with equity.

Discount Rate

The discount rate used to measure the total OPEB liability was 6.25% for the actuarial valuations as of January 1, 2018 and 2017. 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 Liability –

The following table shows the Total OPEB Liability, Plan Fiduciary Net Position and Net OPEB Liability as of January 1, 2018, and the changes during this period, based on the valuation measurement date of January 1, 2018 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB Liability (a-b)
Balances at 1/1/2017	$ 325,344	$ 142,509	$ 182,835
Changes for the year:			
Service cost	2,760	-	2,760
Interest	20,032	-	20,032
Differences between expected and actual experience	(19,570)	-	(19,570)
Changes of assumptions	5,585	-	5,585
Contributions - employer	-	28,439	(28,439)
Net investment income	-	21,350	(21,350)
Benefit payments	(15,414)	(15,414)	-
Administrative expense		(70)	70
Net changes	(6,607)	34,305	(40,912)
Balances at 1/1/2018	$ 318,737	$ 176,814	$ 141,923
Net position as a % of Total OPEB Liability	55.5%		

There were changes made in certain assumptions for the valuation measurement date of January 1, 2018. The mortality assumption was updated to the RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2017 with generational projection. The health care trend rates were also updated.

Sensitivity of the Net OPEB Liability to Changes in the Discount Rate

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using a discount rate that is 1-percentage-point lower (5.25%) or 1-percentage-point higher (7.25%) than the discount rate (6.25%) at the measurement date of January 1, 2018 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB Liability	$ 181,577	$ 141,923	$ 108,851

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

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 6.7% initial to 3.5% ultimate, Post-Medicare ranging from 7.7% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 8.7% initial to 5.5% ultimate, Post-Medicare ranging from 9.7% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 7.7% initial to 4.5% ultimate, Post-Medicare ranging from 8.7% initial to 4.5% ultimate) at the measurement date of January 1, 2018 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB Liability	$ 109,596	$ 141,923	$ 180,578

The following table shows the Total OPEB Liability, Plan Fiduciary Net Position and Net OPEB Liability as of January 1, 2017, and the changes during this period, based on the valuation measurement date of January 1, 2017 (in 000's):

	Total OPEB Liability (a)	Plan Fiduciary Net Position (b)	Net OPEB Liability (a-b)
Balances at 1/1/2016	$ 333,833	$ 75,224	$ 258,609
Changes for the year:			
Service cost	3,322	-	3,322
Interest	20,658	-	20,658
Differences between expected and actual experience	(203)	-	(203)
Changes of assumptions	(18,807)	-	(18,807)
Contributions - employer	-	74,712	(74,712)
Net investment income	-	6,101	(6,101)
Benefit payments	(13,459)	(13,459)	-
Administrative expense		(69)	69
Net changes	(8,489)	67,285	(75,774)
Balances at 1/1/2017	$ 325,344	$ 142,509	$ 182,835
Net position as a % of Total OPEB Liability	43.8%		

There were changes made in certain assumptions for the valuation measurement date of January 1, 2017. The mortality assumption was updated to the RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2016 with generational projection. The health care trend rates were also updated.

In December 2016, the District initiated a voluntary early retirement incentive program ('Program") to all regular, full-time employees, excluding senior management, who met certain retirement-eligible criteria. There were 121 employees who accepted the offer. The impact of the Program was included in the 1/1/2017 actuarial valuation.

Sensitivity of the Net OPEB Liability to Changes in the Discount Rate

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using a discount rate that is 1-percentage-point lower (5.25%) or 1-percentage-point higher (7.25%) than the discount rate (6.25%) at the measurement date of January 1, 2017 (in 000's):

	1% Decrease	Discount Rate	1% Increase
Net OPEB Liability	$ 224,980	$ 182,835	$ 147,850

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

The following table shows the net OPEB liability of the District, as well as what the net OPEB liability would be if it were calculated using healthcare cost trend rates that are 1-percentage-point lower (Pre-Medicare ranging from 6.3% initial to 3.5% ultimate, Post-Medicare ranging from 8.1% initial to 3.5% ultimate) or 1-percentage-point higher (Pre-Medicare ranging from 8.3% initial to 5.5% ultimate, Post-Medicare ranging from 10.1% initial to 5.5% ultimate) than the healthcare cost trend rates (Pre-Medicare ranging from 7.3% initial to 4.5% ultimate, Post-Medicare ranging from 9.1% initial to 4.5% ultimate) at the measurement date of January 1, 2017 (in 000's):

	1% Decrease	Healthcare Cost Trend Rates	1% Increase
Net OPEB Liability	$ 148,629	$ 182,835	$ 223,946

OPEB Plan Fiduciary Net Position

The following table shows information on the OPEB Plan Fiduciary Net Position as of January 1, (in 000's):

	2018	2017
Assets:		
Cash and cash equivalents	$ 3,027	$ 9,609
Receivables:		
Contributions	149	53
Investment income	451	261
Investments	173,419	132,875
Total Assets	177,046	142,798
Liabilities:		
Payables:		
Benefits - health care	148	128
Benefits - life insurance	33	29
Professional, administrative and other expenses	-	47
Investment expense	51	85
Total liabilities	232	289
Net Position - Restricted for Other Postemployment Benefits	$ 176,814	$ 142,509

The following tables set forth the OPEB assets that are accounted for and reported at fair value on a recurring basis by level within the fair value hierarchy as of January 1, 2018 (in 000's):

	Level 1	Level 2	Level 3	Total
U.S. Treasury and government agency securities	$ -	$ 15,956	$ -	$ 15,956
Corporate issues	-	28,056	-	28,056
Foreign issues	-	6,629	-	6,629
Municipal issues	-	779	-	779
Domestic common stocks	45,678	-	-	45,678
Foreign stocks	4,002	-	-	4,002
Mutual funds	64,183	-	-	64,183
	$113,863	$ 51,420	$ -	$ 165,283
Other investments measured at net asset value (A) ...				8,136
				$ 173,419

(A) The fair value of investments in a real estate fund was estimated using the net asset value per share (or its equivalent) practical expedient and was not classified in the fair value hierarchy. The fund allows for quarterly redemption with a 90-day notice. There are no unfunded commitments to the fund as of January 1, 2018.

The following tables set forth the OPEB assets that are accounted for and reported at fair value on a recurring basis by level within the fair value hierarchy as of January 1, 2017 (in 000's):

	Level 1	Level 2	Level 3	Total
U.S. Treasury and government agency securities	$ -	$ 2,678	$ -	$ 2,678
Corporate issues	-	18,162	-	18,162
Foreign issues	-	5,161	-	5,161
Municipal issues	-	766	-	766
Domestic common stocks	39,002	-	-	39,002
Foreign stocks	3,569	-	-	3,569
Mutual funds	63,537	-	-	63,537
	$106,108	$ 26,767	$ -	$ 132,875

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 $8.4 million for 2018, as calculated under the GASB 75 guidance. With regulatory accounting, OPEB expense and the amount included in rates was $53.2 million for 2018. The regulatory accounting OPEB expense is higher because it includes the amortization of costs related to prior periods, including a $25.0 million catch-up rate collection for the net OPEB liability for past production-level services.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2018 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 2,291	$ 25,957
Difference between actual and expected earnings	2,221	9,635
Contributions made during the year ended December 31, 2018	56,706	-
	$ 61,218	$ 35,592

The deferred outflows of resources related to the contributions made during the year ended December 31, 2018 will be recognized in the actuarial valuation with a measurement date of January 1, 2019. 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
2018	$ (5,112)
2019	(5,112)
2020	(6,078)
2021	(6,839)
2022	(4,505)
2023	(3,237)
2024	(197)
Total	$(31,080)

OPEB expense was $16.7 million for 2017, as calculated under the GASB 75 guidance. With regulatory accounting, OPEB expense and the amount included in rates was $53.3 million for 2017. This amount included a $25.0 million catch-up rate collection for the net OPEB liability for past production-level services.

The following table summarizes the reported deferred outflows and deferred inflows of resources as of December 31, 2017 (in 000's):

	Deferred Outflows	Deferred Inflows
Difference between actual and expected experience	$ 3,030	$ 16,475
Difference between actual and expected earnings	3,283	-
Contributions made during the year ended December 31, 2017	28,290	-
	$ 34,603	$ 16,475

The deferred outflows of resources related to the contributions made during the year ended December 31, 2017 will be recognized in the actuarial valuation with a measurement date of January 1, 2018. 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
2018	$ (733)
2019	(733)
2020	(734)
2021	(1,699)
2022	(2,461)
2023	(2,535)
2024	(1,267)
Total	$(10,162)

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 $43.0 million at December 31, 2018. These contracts expire at various times through the end of 2020. 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 2021, a contract for enrichment services through 2024, if needed, and a contract for fabrication services through January 18, 2034, if needed, the end of the current operating license of CNS. These commitments for nuclear fuel material and services have combined estimated future payments of $195.0 million.

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 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% of its original participation share. 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 GGS and CNS of 50 MW which began January 1, 2011 and continues through December 31, 2023.

The District has entered into power sales agreements with LES for the sale to LES of 8% of the net power and energy of GGS. In return, LES agrees to pay 8% of all costs attributable to GGS. This agreement is to terminate upon the later of the last maturity of the debt attributable to GGS or the date on which the District retires such station from commercial operation. The District and LES had previously entered into a Participation Power Sales Agreement with respect to Sheldon whereby LES had agreed to pay 30% of all costs (excluding fuel costs) attributable to Sheldon. The District and LES terminated the Participation Power Sales Agreement with respect to Sheldon effective December 31, 2017. LES paid the District $10.5 million as a termination fee in full satisfaction of its obligations under the Sheldon Station Participation Power Sales Agreement.

The District has wholesale power purchase commitments with the Western Area Power Administration through 2020 with annual minimum future payments of approximately $27.7 million. These purchases are subject to rate changes.

The District owns and operates the 60 MW Ainsworth Wind Energy Facility and has 20-year participation power agreements to sell 28 MW to four other utilities. One of which, JEA, has given notice to terminate on December 31, 2019. 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 an accredited net capacity of 37 MW.

The District has entered into long-term PRO Agreements having initial terms of 15, 20, or 25 years with 79 municipalities for the operation of certain retail electric distribution systems. These PRO Agreements expire on various years between 2023 and 2042. 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.

C. *Wholesale Power Contracts* –

The District serves its wholesale customers under total requirements contracts that require them to purchase total demand 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 37 municipalities. One public power district and 9 municipalities are served under 2002 Wholesale Power Contracts ("2002 Contracts"), which expire on December 31, 2021. In 2018, one of the District's wholesale customers consolidated with another District wholesale customer.

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 remained below the Performance Standard Percentile.

The following table lists the District's wholesale power costs percentile for the calendar years 2013 to 2017 set forth in the CFC Data:

	CFC Data
Year	Percentile
2013	31.0%
2014	27.6%
2015	31.3%
2016	28.2%
2017	26.0%

The District has ten wholesale customers remaining on the 2002 Contracts. The 2002 Contracts allow a wholesale customer to reduce its purchases of demand and energy upon giving appropriate notice. Reductions could amount to as much as 90% of their demand and energy requirements under certain circumstances. All wholesale customers under the 2002 wholesale contracts are required to purchase at least 10% of their demand and energy from the District through December 31, 2021.

The District has received notices from all wholesale customers under the 2002 Contracts as to their intent to level off, reduce, or terminate the requirements for various amounts from 2017 through 2021. These wholesale customers represented 3.6% and 4.8% of operating revenues for 2018 and 2017, respectively. The District expects that no requirements of said wholesale customers will be served by the District in 2022, and such wholesale customers will purchase all of their electric requirements from other suppliers. The District expects to sell the energy not sold to such wholesale customers into the SPP Integrated Market and continues to explore additional firm requirement and/or fixed price agreements.

The 2016 wholesale rates resulted in a 0.6% increase for wholesale customers who signed the 2016 Contracts, and a 3.8% increase for those wholesale customers who remained under the 2002 Contracts. Customers under the 2002 Contracts will pay their share of previously incurred OPEB costs (or the catch-up amount) through rates prior to the expiration of their contracts in 2021. Customers under the 2016 Contracts received a discount for the deferral of OPEB collections, extending those collections into the new contract period and resulting in the lower net wholesale rate increase. The District financed with taxable debt the 2016 Contracts customers' share of the OPEB catch-up amount for 2016, 2017 and 2018. The customers under the 2016 Contracts will commence payment of the related debt service beginning in 2022, the year after the expiration of the 2002 Contracts.

Eight of the ten wholesale customers who remained under the 2002 Contracts filed for binding arbitration in May 2016 claiming the 2016 wholesale rate violated the 2002 Contracts, was contrary to Nebraska's rate statute and reflected bad faith toward those not signing the 2016 Contracts. These customers later added the OPEB component of the 2017 wholesale rate to their dispute. The arbitration panel ruled in favor of the District in April 2017. This case was appealed and argued before the Nebraska Supreme Court ("Court") in March 2018. The Court upheld the 2017 arbitration decision in June 2018. After the arbitration filing in May 2016, disputed revenue collections for OPEB were set aside in separate accounts until the Court decision. These disputed amounts were contributed to the OPEB Trust in 2018.

The Northeast Nebraska Public Power District filed a lawsuit in the District Court of Wayne County, Nebraska ("District Court") regarding the demand and energy reduction provisions under the 2002 Contract. The District Court issued an order dated February 26, 2016, in favor of the Northeast Nebraska Public Power District which allows it to reduce demand and energy purchases from the District by 30% in 2018, 60% in 2019 and 90% in 2020. The District Court decision will apply to certain other customers who have given notice for demand and energy reductions under the 2002 Contract. On March 23, 2016, the District Court filed a notice of appeal. The Nebraska Court of Appeals affirmed the District Court decision in June 2017. The Nebraska Supreme Court declined to review the matter in September 2017.

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 entered into a Transmission Facilities Construction Agreement effective June 15, 2009, with TransCanada Keystone Pipeline, LP ("Keystone"). This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of Keystone to the District's transmission system. Cost of the project was $8.4 million and repayment by Keystone, over a 10-year period, began in June 2010 with a remaining balance due the District of $1.6 million and $2.6 million as of December 31, 2018 and 2017, respectively.

The District and Heartland had previously entered into a Transmission Service Agreement ("Agreement") with an expiration date for the related transmission services of December 31, 2030. The District and Heartland terminated the Agreement with respect to such services effective December 31, 2018. Heartland paid the District $35.0 million in 2018 as a termination fee in full satisfaction of its obligations under the Agreement.

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 CNS for an additional 20 years until January 18, 2034. CNS entered the 20-year period of extended operation on January 18, 2014.

In October 2003, the District entered into an agreement (the "Entergy Agreement") for support services at CNS with Entergy Nuclear Nebraska, LLC ("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% during the five-year period. The Entergy Agreement requires the District to reimburse Entergy's cost of providing services, and to pay Entergy annual management fees. These annual management fees were $15.2 million and $18.5 million for 2018 and 2017, respectively. These fees will increase by an additional $3.5 million and $3.0 million in 2023 and 2024, respectively. Under the amended Entergy Agreement, Entergy can also earn additional annual incentive fees of up to $4.0 million per year, with the exception of the years 2018-2022 where the amount is limited to $3.5 million per year, if CNS achieves identified safety and regulatory performance targets.

Entergy has achieved certain safety and regulatory performance targets during the term of the Entergy Agreement and has been eligible for at least a portion of this annual incentive fee.

Since the earthquake and tsunami of March 11, 2011, that impacted the Fukushima Dai-ichi Plants in Japan, the District, as well as the rest of the nuclear industry, has been working to first understand the events that damaged the reactors and associated fuel storage pools and then look to any changes that might be necessary at the United States nuclear plants.

On March 12, 2012, the NRC issued three orders to the U.S. nuclear industry as a result of the Fukushima Dai- ichi event in Japan. The first order requires all domestic nuclear plants to better protect supplemental safety equipment and obtain additional equipment as necessary to protect the reactor in the event of beyond design basis external events. The second order requires nuclear plant operators of boiling water reactors like CNS to modify reactor licenses with regard to reliable hardened containment wetwell vents. The third order requires nuclear plant operators to add reliable spent fuel pool water level instrumentation. The NRC has also issued a request for information pertaining to re-evaluation of seismic and flooding hazards, and a communications and staffing assessment for emergency preparedness. CNS has completed all requirements of the three NRC orders.

Since the initial site-specific seismic reevaluation analysis for CNS that resulted in no identified seismic-related modifications to CNS, the District has performed additional seismic analyses, which include a High Frequency Evaluation and Spent Fuel Pool Evaluation, and has worked to answer additional questions from the NRC on this topic. A Seismic Probabilistic Risk Assessment was not required. No modifications are required as a result of the additional seismic analysis.

The District continues to work with the U.S. Army Corps of Engineers and the NRC to validate the data necessary to complete the CNS flood hazard reevaluation. The District submitted its updated flooding analysis to the NRC in February 2015. The District responded to NRC questions and resubmitted the updated flood hazard reevaluation in September 2016. CNS submitted an Integrated Assessment Report for external flooding in December 2018. Based on current interim, and long-term strategies for flooding mitigation, it is not expected that any modifications will be required as a result of the flood hazard reevaluations. All equipment and materials required to mitigate the identified impacts associated with the flood hazard reevaluation have been purchased and the equipment required has been installed. Additional equipment purchased, but not required to be installed unless an issue occurs, is stored on-site in dedicated storage facilities.

The District's cost estimate for plant modifications associated with the NRC's Fukushima Dai-ichi related orders is currently estimated to cost $20.5 million, which is expected to be funded primarily from the revenues of the District and from the proceeds of General Revenue Bonds. As of December 31, 2018, $19.5 million has been spent on plant modifications.

CNS 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 CNS 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 CNS at no additional cost to the District until the expiration of the current NRC license in May 2022 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 CNS 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 $129.5 million for the years 2009 through 2018. 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 CNS. The balance in the regulatory liability was $75.4 million and $66.2 million as of December 31, 2018 and 2017, respectively.

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 CNS, 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 CNS 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 NRC has five performance categories included in the ROP Action Matrix Summary that is part of this process. As of December 31, 2018, CNS 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 CNS approximately every two years. The most recent refueling and maintenance outage began on September 29, 2018 and was completed on November 17, 2018. During this outage, in addition to replacing 180 fuel assemblies and conducting routine maintenance, the entire length of the emergency station startup transformer buss duct insulation was replaced, one of the reactor feed pump turbines was overhauled, and the reactor core isolation cooling governor controls were replaced.

Significant operations and maintenance expenses are incurred in an outage year. The Board 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 CNS are paying the costs, commencing in 2017. The regulatory liability for the pre-collection of outage costs was $20.0 million as of December 31, 2017 and was eliminated through revenue recognition during the 2018 outage year.

A Notice of Unusual Event ("NOUE") was issued at CNS due to rising water levels in the Missouri River on March 15, 2019. The NOUE was exited on March 24, 2019, when the water levels had receded. CNS operations were not impacted. Additional information is included in Note 14.

F. *Environmental –*

<u>Water</u>

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 NDEQ establishes the requirements for the District's compliance with the Clean Water Act through issuance of National Pollutant Discharge Elimination System permits. NDEQ issued the District permits for the following facilities: GGS, Sheldon, CNS, Beatrice Power Station, Canaday Station, Kearney Hydro and the North Platte Office Building. The District anticipates some level of fish protection equipment technology installation, both for impingement and entrainment, may be necessary for CNS and only for impingement at GGS. Until the final compliance options are determined, the District does not know the financial impact of this regulation.

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 CNS, GGS, Sheldon and Canaday Station, the Effluent Rule only has an impact on Sheldon. Sheldon will be required to be a zero discharge facility for bottom ash transport water by December 31, 2023. The District is currently analyzing the options for compliance, which is estimated to cost $2.4 million. EPA has listed this rule as one they will consider for regulatory reform and the requirements may be subject to change.

Acid Rain Program

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: GGS, Sheldon, 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 2024, the District expects to have sufficient Acid Rain allowances to cover affected facilities through 2024, but may be required to purchase additional allowances in the future.

Mercury and Air Toxic Standards

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 will require 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 GGS and Sheldon, are in compliance with the MATS Rule.

Cross-State Air Pollution Rule

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 2024, the District expects to have sufficient CSAPR allowances to cover affected facilities emission requirements through 2024, but may be required to purchase additional allowances in the future.

Regional Haze

The EPA issued final regulations for a Regional Haze Program in June 1999. 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. For phase one of the Regional Haze rule the Best Available Retrofit Technology ("BART") Report was submitted to the NDEQ in August 2007 and a revised report was submitted in February 2008. The BART Report proposed that the Best Available Retrofit Technology to meet regional haze requirements at GGS would be low NO_x burners on Units No. 1 and No. 2 and no additional controls for SO_2. Low NO_x burners have now been installed on both units at GGS. The NDEQ State Implementation Plan ("SIP") agreed with the BART Report. The NDEQ submitted the SIP to the EPA for approval on June 30, 2011.

On May 30, 2012, the EPA issued a rule pertaining to the Regional Haze Program that would approve the trading program in CSAPR as an alternative to determining BART for power plants. As a result, states in the CSAPR region may substitute the trading program in CSAPR for source-specific BART for SO_2 and/or NO_x emissions as specified by CSAPR.

On July 6, 2012, the EPA issued the final rule on the Nebraska Regional Haze SIP. The final rule approved the GGS NO_x portion of the SIP but disapproved the SO_2 portion of the SIP for GGS. The EPA issued a Federal Implementation Plan ("FIP") for GGS which stated that BART for SO_2 control at GGS is compliance with CSAPR. The District is currently in compliance with all requirements of phase one of the Regional Haze rule.

On January 10, 2017, the EPA issued final changes to the Regional Haze regulations for the second planning phase of the Regional Haze Rule. The District is evaluating the proposed changes but will not know the full impact to the District until the State and the EPA begin implementing the second phase of the Regional Haze rule. The State is required to submit their SIP for the second phase of the Regional Haze rule by July 31, 2021.

Clean Air Act Compliance (New Source Review)

As part of EPA's nationwide investigation and enforcement program for coal-fired power plants' compliance with the Clean Air Act including New Source Review requirements, on December 4, 2002, the Region 7 office of the EPA began an investigation to determine the Clean Air Act compliance status of GGS and Sheldon. The District timely responded to EPA's requests for information. By letter dated December 8, 2008, EPA Region 7 sent a Notice of Violation ("NOV") to the District which alleges that the District violated the Clean Air Act by undertaking five projects at GGS from 1991 through 2001 without obtaining the necessary permits. In February and August 2009, District representatives met with federal government representatives to discuss the NOV and no additional meetings have been scheduled. In general, enforcement action by EPA against the District for alleged noncompliance with Clean Air Act requirements, if upheld after court review, can result in the requirement to install expensive air pollution control equipment that is the BART and the imposition of monetary penalties ranging from $25,000 to $32,500 per day for each violation. The District cannot determine at this time whether it will have any future financial obligation with respect to the NOV.

On July 22, 2016, EPA Region 7 sent a new 114(a) request for documents and information regarding the compliance status of GGS. On December 27, 2016, EPA Region 7 sent a 114(a) follow-up request for additional information on certain projects that were identified in the July 22, 2016, 114(a) request. The EPA is reviewing whether there have been physical or operational changes since November 8, 2007 which resulted in, or could result in, increased emissions including projects underway or planned for the next two years. The District gathered documents and information and provided it to the EPA. Failure to comply with the Clean Air Act can result in fines as described above and/or requirements to install additional emission control equipment. The District believes GGS has been operated and maintained in compliance with the requirements of the Clean Air Act.

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 State Plan. 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 and a decision was expected in early 2017. Prior to the Court issuing a decision, the EPA asked the Court to hold the legal process in abeyance while the EPA worked to repeal and replace the CPP.

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. The proposed ACE rule makes the determination that BSER for CO_2 at individual fossil-fuel fired steam generating units to be heat rate improvement projects. The EPA is also proposing to update the New Source Review process. The District is currently reviewing the proposed rule, but it is not possible to determine the potential impact of the proposed rule until it is finalized and the NDEQ develops the State Plan.

Impact from Changes to Environmental Regulatory Requirements

Any changes in the environmental regulatory requirements imposed by federal or state law which are applicable to the District's generating stations 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. *Sale of Spencer Hydro Facility* –

In September 2015, a memorandum of understanding ("MOU") was signed for the sale of the District's Spencer Hydro ("Spencer") facility, including dam, structures, land, water appropriations, and perpetual easements for the reservoir, to the Niobrara River Basin Alliance (Five Natural Resource Districts) and the Nebraska Game and Parks Commission for $12.0 million. The District was to provide an in-kind contribution of $3.0 million and the buyers were to pay $9.0 million to the District. The 2015 MOU that was signed expired on June 1, 2017. Following the expiration, the parties have negotiated an agreement for the sale and purchase of the Spencer facility. The new agreement, with similar terms, was signed on September 24, 2018 and expires on January 31, 2021. The Spencer facility was severely damaged as a result of extreme adverse weather conditions outlined in Note 14.

13. LITIGATION:

On January 1, 2016, Tri-State Generation and Transmission Association, Inc. ("Tri-State") became a transmission member of SPP and its transmission facilities in western Nebraska, and the corresponding annual transmission revenue requirements were placed under the SPP tariff. SPP filed at Federal Energy Regulatory Commission ("FERC") to place the Tri-State transmission facilities in the District's pricing zone rather than establish a new pricing zone for Tri-State. The District protested the filing at FERC, because it results in approximately a $4.3 million per year, or 8%, cost shift increase to the transmission customers in the District's pricing zone. As a result of the District's protest, FERC set the matter for hearing before an administrative law judge and the District and other parties submitted briefs and testimony on the proper pricing zone and whether SPP's decision is discriminatory and an unjust and unreasonable cost shift to the District. On February 23, 2017, the administrative law judge issued an initial decision upholding the SPP pricing zone placement and made recommended conclusions to FERC. On May 17, 2018, FERC entered an order affirming the administrative law judge's initial decision. On June 18, 2018, the District filed a request for rehearing of that order. FERC's Order of January 17, 2019, denied that request for rehearing. On March 15, 2019, the District filed a petition for review of the January 17, 2019 Order with the United States Eighth Circuit Court of Appeals.

In 2017, the Nebraska Department of Revenue ("NDOR") conducted a sales and use tax audit on the District's records for the audit period of June 1, 2014 through May 31, 2017. NDOR issued a Notice of Deficiency Determination ("Determination") to the District for approximately $6.5 million, including interest and penalties of over $1.0 million, on January 30, 2018. Beyond the minor sales and use tax corrections contained in a normal audit Determination, the NDOR assessed almost $5.5 million of tax on the payments to municipalities under PRO Agreements. The District disagrees with the NDOR's assessment and filed a Petition for Redetermination to formally challenge the Determination on March 29, 2018.

Information on litigation with wholesale customers under the 2002 Contracts is included in Note 12.C.

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, taking into account estimated amounts provided in the financial statements and insurance coverage, are not material.

14. SUBSEQUENT EVENTS:

Impact on Operations and Damages from Adverse Weather Conditions –
The Governor of Nebraska declared a state of emergency on March 12, 2019, in anticipation of potential ice jams, flooding and a variety of extreme adverse weather conditions, causing severe ice buildup in several streams and river basins. On March 13, 2019, extreme adverse weather conditions began which resulted in widespread loss and devastation in Nebraska and other areas in the Midwestern United States. For the District, the impact was experienced across the state and included extensive damage to the Spencer Hydro facility and dam, the reporting of a NOUE at CNS due to rising water levels in the Missouri River, and various transmission and distribution outages.

The Spencer Hydro facility was not a significant generating source for the District, only generating 10,509 MWh in 2018. There is a purchase agreement in place for the sale of the Spencer Hydro facility, including dam, structures, land, water appropriations, and perpetual easements for the reservoir, which requires the parties to close on or before January 31, 2021. The impact of the damages sustained by the Spencer Hydro facility on this purchase agreement, if any, is yet to be determined. Additional information on this purchase agreement is included in Note 12.G.

The rising water in the Missouri River resulted in the declaration of a NOUE with the NRC and the public around CNS on March 15, 2019, when the Missouri River reached 899.05 feet at CNS. The declaration was anticipated because of increased snow melt, frozen ground and heavy rain conditions in Nebraska combined with releases of water from upstream dams in South Dakota that escalated from 17,000 cubic feet per second to as high as 90,000 cubic feet per second, easing the pressure on the dams. The notification was made as part of a safety and emergency preparedness plan CNS follows when flooding conditions are in effect. Procedures dictate when the Missouri River's water level reaches 42.5 feet, or greater than 899 mean sea level, a NOUE is declared. The NOUE was exited on March 24, 2019, when the water levels had receded. CNS operations were not impacted by these adverse weather conditions.

The estimated costs of the damages to the District, not covered by insurance, is less than $10.0 million. Most of the costs are expected to be eligible for reimbursement from the Federal Emergency Management Agency.

SUPPLEMENTAL SCHEDULES (UNAUDITED)

Calculation of Debt Service Ratios in accordance with the General Revenue Bond Resolution for the years ended December 31, (in 000's)	2018	2017
Operating revenues	$ 1,144,858	$ 1,101,642
Operating expenses	(1,025,185)	(988,931)
Operating income	119,673	112,711
Investment and other income	26,896	23,591
Debt and related expenses	(63,861)	(64,986)
Increase in net position	82,708	71,316
Add:		
Debt and related expenses[1]	63,861	64,986
Depreciation and amortization[2]	133,057	122,559
Payments to retail communities[3]	27,745	27,102
Amortization of current portion of financed nuclear fuel[4]	35,102	42,198
Amounts collected from third party financing arrangements[5]	986	938
	260,751	257,783
Deduct:		
Investment income retained in construction funds[6]	632	645
Unrealized gain (loss) on investment securities	204	(2,595)
	836	(1,950)
Net revenues available for debt service under the General System Bond Resolution	$ 342,623	$ 331,049
Amounts deposited in the General System Debt Service Account:		
Principal	$ 98,590	$ 84,125
Interest	69,841	71,198
	$ 168,431	$ 155,323
Ratio of net revenues available for debt service to debt service deposits	2.03	2.13

(1) Debt and related expenses, exclusive of interest on customer deposits, is not an operating expense as defined in the Resolution.
(2) Depreciation and amortization are not operating expenses as defined in the Resolution.
(3) Under the provisions of the Resolution, the payments required to be made by the District with respect to the Professional Retail Operating 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 Resolution. As of July 31, 2015, the effective date of the TRCA, amortization of nuclear fuel expense under the TRCA is excluded from the debt service calculation as the District's obligation to make payments under the TRCA is subordinate to the District's obligation to pay debt service on General Revenue Bonds.
(5) The payments received by the District from third party financing arrangements are included as Revenues under the Resolution, but are not recognized as revenue under GAAP.
(6) Interest income on investments held in construction funds is not Revenue as defined in the Resolution.

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

Total OPEB Liability	2018	2017	2016
Service Cost	$ 2,760	$ 3,322	$ 3,229
Interest	20,032	20,658	19,876
Differences between Expected and Actual Experiences	(19,570)	(203)	13,657
Changes of Assumptions	5,585	(18,807)	(9,149)
Benefit Payments, net of employee contributions	(15,414)	(13,459)	(16,902)
Net Change in Total OPEB Liability	(6,607)	(8,489)	10,711
Total OPEB Liability (beginning)	325,344	333,833	323,122
Total OPEB Liability (ending) (a)	$ 318,737	$ 325,344	$ 333,833
Plan Fiduciary Net Position			
Contributions	$ 28,439	$ 74,711	$ 28,242
Net Investment Income	21,350	6,102	(453)
Benefit Payments, net of employee contributions	(15,414)	(13,459)	(16,902)
Administrative Expense	(70)	(69)	(150)
Net Change in Plan Fiduciary Net Position	34,305	67,285	10,737
Plan Fiduciary Net Position (Beginning)	142,509	75,224	64,487
Plan Fiduciary Net Position (Ending) (b)	$ 176,814	$ 142,509	$ 75,224
Net OPEB Liability (Ending) (a) - (b)	$ 141,923	$ 182,835	$ 258,609
Net Position as a % of Total OPEB Liability	55.5%	43.8%	22.5%

GASB Statement No. 75, Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans, was implemented by the District in 2016. The provisions of this Statement were not applied to prior periods, as it was not practical to do so as the information was not readily available. The OPEB schedules are intended to show information for ten years. Additional years will be displayed when available.

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

	2018	2017	2016
Actuarially Determined Contribution	$ 18,572	$ 21,006	$ 28,283
Contributions Made in Relation to the Actuarially Determined Contribution	56,706	28,439	74,711
Contribution Deficiency (Excess)	$ (38,134)	$ (7,433)	$ (46,428)

Notes to Schedule:
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.

Methods and assumptions used for 2018 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	15-year closed period
Asset valuation method	5-year smoothed market
Discount rate	6.25%
Healthcare cost trend rates	Pre-Medicare: 7.7% initial, ultimate 4.5% Post-Medicare: 8.7% initial, ultimate 4.5%
Inflation	2.3%
Salary increase	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2017 with generational projection
Retirement Age	Varies by age

Methods and assumptions used for 2017 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	16-year closed period
Asset valuation method	5-year smoothed market
Discount rate	6.25%
Healthcare cost trend rates	Pre-Medicare: 7.3% initial, ultimate 4.5% Post-Medicare: 9.1% initial, ultimate 4.5%
Inflation	2.1%
Salary increase	4.0%
Investment rate of return	6.25%, net of investment expense, including inflation
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2016 with generational projection
Retirement Age	Varies by age

Methods and assumptions used for 2016 –

Actuarial cost method	Entry Age Normal
Amortization method	Level amortization of the unfunded accrued liability
Amortization period	17-year closed period
Asset valuation method	5-year smoothed market
Discount rate	6.25%
Healthcare cost trend rates	Pre-Medicare: 8% initial, ultimate 5%
	Post-Medicare: 6.75% initial, ultimate 5%
Inflation	2.1%
Investment rate of return	6.25%, net of investment expense, including inflation
Mortality	RP-2014 Aggregate table projected back to 2006 using Scale MP-2014 and projected forward using Scale MP-2015 with generational projection
Retirement Age	Varies by age

Schedule of Investment Returns for Years Ended December 31,

	2018	2017	2016
Annual Money-Weighted Rate of Return, Net of Investment Expense	(3.6)%	14.2%	5.8%

GASB Statement No. 75, Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans, was implemented by the District in 2016. The provisions of this Statement were not applied to prior periods, as it was not practical to do so as the information was not readily available. The OPEB schedules are intended to show information for ten years. Additional years will be displayed when available.

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