Omaha Public Power District

2013 Financial Report

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Management's Discussion and Analysis (Unaudited)

USING THIS FINANCIAL REPORT

The Financial Report for the Omaha Public Power District (OPPD or Company) includes this Management's Discussion and Analysis, Financial Statements and Notes to the Financial Statements. The basic Financial Statements consist of the Statement of Net Position, the Statement of Revenues, Expenses and Changes in Net Position and the Statement of Cash Flows. The Financial Statements have been prepared in accordance with generally accepted accounting principles for proprietary funds of governmental entities. Questions concerning any of the information provided in this report should be directed to Investor Relations, 402-636-3286.

Management's Discussion and Analysis (MD&A) – This unaudited information provides an objective and easily readable analysis of OPPD's financial activities based on currently known facts, decisions or conditions. In the MD&A, financial managers present both short-term and long-term analyses of the Company's activities. The MD&A should be read in conjunction with the Financial Statements and related Notes. This document contains forward-looking statements based on current plans.

Statement of Net Position – This statement reports resources with service capacity (assets) and obligations to sacrifice resources (liabilities). Deferrals result from outflows and inflows of resources that have already taken place but are not recognized in the financial statements as expenses and revenues because they relate to future periods. Net Position is the residual interest in the Company. On the Statement of Net Position, the sum of assets and deferred outflows equals the sum of liabilities, deferred inflows and net position. This statement facilitates the assessment and evaluation of liquidity, financial flexibility and capital structure.

Statement of Revenues, Expenses and Changes in Net Position – All revenues and expenses are accounted for in this statement. This statement measures the activities for the year and can be used to determine whether the rates, fees and other charges are adequate to recover expenses.

Statement of Cash Flows – This statement reports all cash receipts and payments summarized by net changes in cash from operating, capital and related financing and investing activities.

Notes to the Financial Statements (Notes) – These notes provide additional detailed information to support the Financial Statements.

Statistics – This unaudited section provides additional comparison information.

OVERVIEW

The financial position and results of operations were similar for 2013 and 2012. Fort Calhoun Station (FCS) was in an outage during both of these years and resumed operations on December 21, 2013. This extended outage had an adverse impact on off-system sales revenues and operating expenses. OPPD lessened the impact on customer-owners through insurance recoveries, the use of regulatory accounting and cost reductions. The most significant cost reductions in 2013 were from lower prices for coal transportation and reductions in employee benefit expenses. The following sections include more detailed information on financial activities.

FINANCIAL POSITION AND RESULTS OF OPERATIONS

The following table summarizes OPPD's financial position as of December 31 (in thousands).

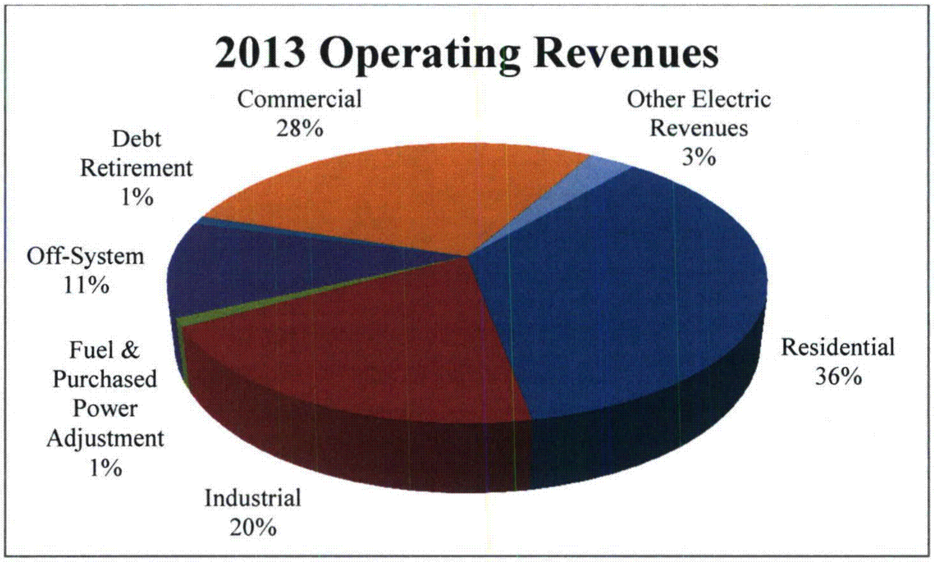
Condensed Statements of Net Position	**2013**	**2012**
Current Assets	$ 700,882	$ 809,696
Other Long-Term Assets and Special Purpose Funds	757,626	683,886
Capital Assets	3,359,141	3,342,731
Total Assets	4,817,649	4,836,313
Deferred Outflows of Resources	29,310	33,502
Total Assets and Deferred Outflows	$ 4,846,959	$ 4,869,815
Current Liabilities	$ 222,405	$ 385,947
Long-Term Liabilities	2,717,966	2,615,556
Total Liabilities	2,940,371	3,001,503
Deferred Inflows of Resources	37,000	54,000
Net Position	1,869,588	1,814,312
Total Liabilities, Deferred Inflows and Net Position	$ 4,846,959	$ 4,869,815

The following table summarizes OPPD's operating results for the years ended December 31 (in thousands).

Operating Results	**2013**	**2012**
Operating Revenues	$ 1,090,213	$ 1,047,997
Operating Expenses	(958,338)	(928,961)
Operating Income	131,875	119,036
Other Income	20,956	28,418
Interest Expense	(97,555)	(92,625)
Net Income	$ 55,276	$ 54,829

Operating Revenues

The following chart illustrates 2013 operating revenues by category and percentage of the total. Other electric revenues include connection charges, late payment charges, rent from electric property, wheeling fees, insurance recoveries for prior years and miscellaneous revenues.



2013 Compared to 2012 – Total operating revenues were $1,090,213,000 for 2013, an increase of $42,216,000 or 4.0% over 2012 operating revenues of $1,047,997,000.

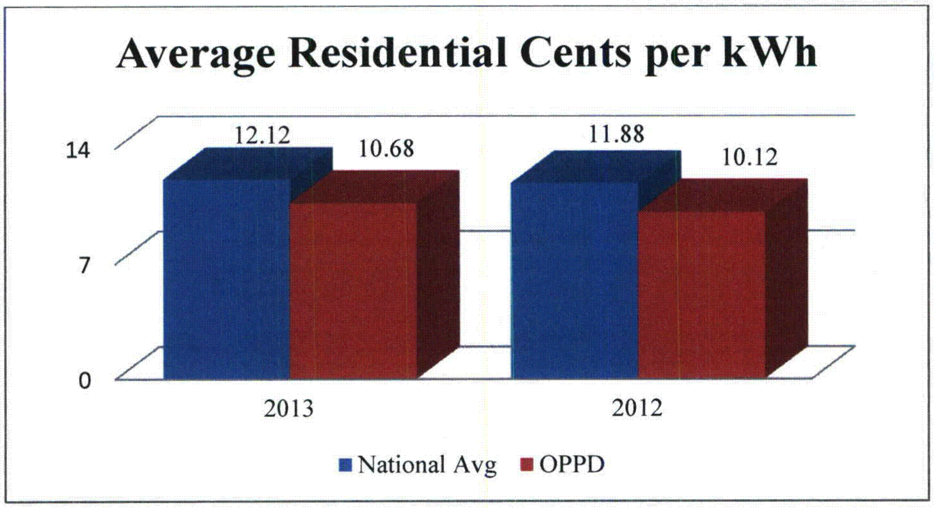
- Revenues from retail sales were $942,291,000 for 2013, an increase of $72,385,000 or 8.3% over 2012 revenues of $869,906,000. The change in retail revenues was primarily due to higher energy prices and an increase in the adjustment for the under-recovery of fuel and purchased power expenses.
- Revenues from retail sales included $17,000,000 in transfers from the Debt Retirement Reserve in both 2013 and 2012.
- Revenues from off-system sales were $118,268,000 for 2013, a decrease of $4,923,000 or 4.0% from 2012 revenues of $123,191,000. The decrease was primarily due to the expiration of a large participation sales contract.
- Other Electric Revenues were $29,654,000 for 2013, a decrease of $25,246,000 or 46.0% from 2012 revenues of $54,900,000. The decrease was primarily due to insurance recoveries received in 2012.

Cents per kWh

The Company strives to manage costs and maximize the public power advantage of low-cost and reliable service.

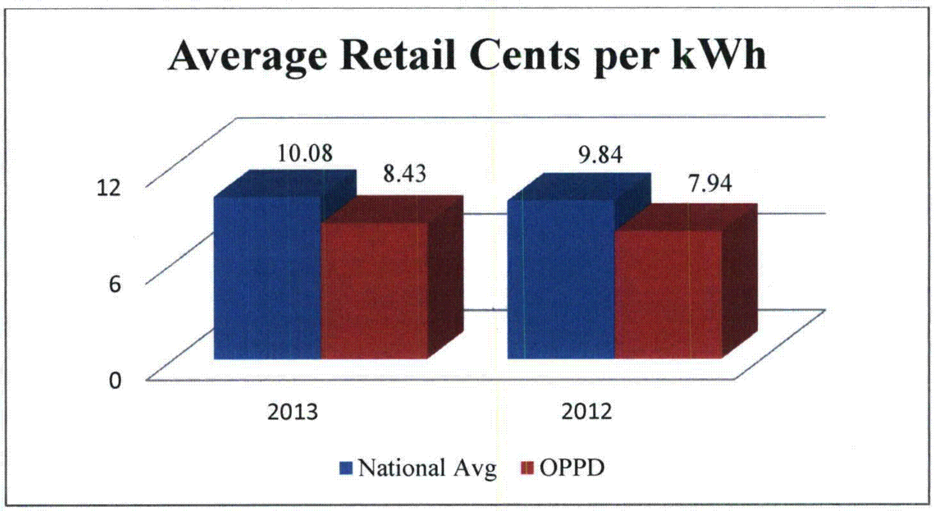
Residential customers paid an average of 10.68 and 10.12 cents per kilowatt-hour (kWh) in 2013 and 2012, respectively. The national average residential cents per kWh according to the Energy Information Administration (EIA), U.S. Department of Energy, was 12.12 for 2013 (preliminary year-to-date December 2013) and 11.88 cents per kWh for 2012. Based on the preliminary EIA data for 2013, OPPD residential rates were 11.9% below the national average.

The following chart illustrates the Company's average residential cents per kWh compared to the national average.



Retail customers paid an average of 8.43 and 7.94 cents per kWh in 2013 and 2012, respectively. The national average retail cents per kWh according to the EIA, was 10.08 for 2013 (preliminary year-to-date December 2013) and 9.84 cents per kWh for 2012. Based on the preliminary EIA data for 2013, OPPD retail rates were 16.4% below the national average.

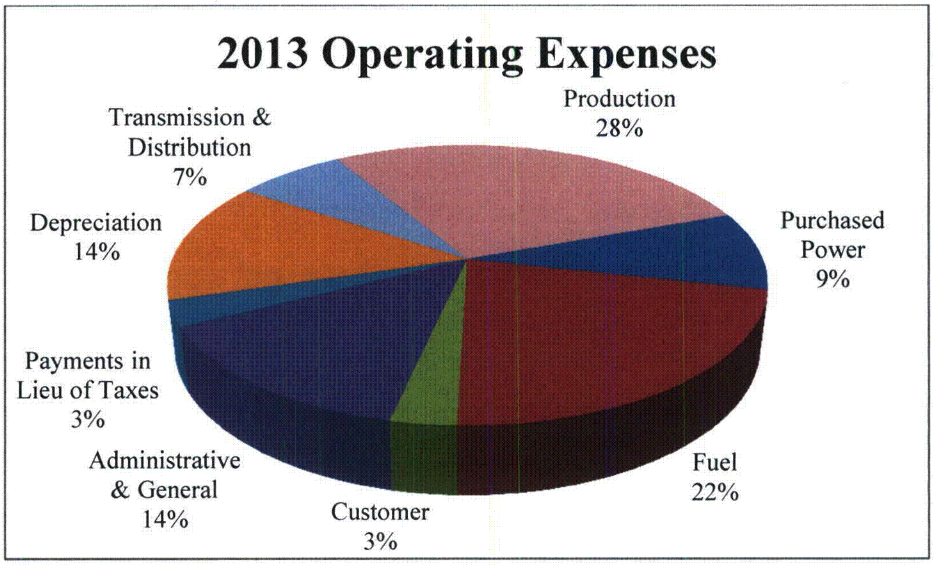
The following chart illustrates the Company's average retail cents per kWh compared to the national average.



General rate adjustments of 7.3% and 4.5% were implemented in January 2013 and 2012, respectively, due to increased operating costs. The adjustments to the Fuel and Purchased Power Adjustment (FPPA) were a decrease of 0.4% for 2013 and an increase of 1.4% for 2012. Cost-containment, the use of regulatory accounting and other risk management efforts have limited these rate adjustments. There were no rate adjustments implemented in January 2014.

Operating Expenses

The following chart illustrates 2013 operating expenses by expense classification and percentage of the total.



2013 Compared to 2012 - Total operating expenses were $958,338,000 for 2013, an increase of $29,377,000 or 3.2% over 2012 operating expenses of $928,961,000.

- Fuel expense decreased $21,024,000 or 8.9% from 2012, primarily due to lower coal transportation costs resulting from the renegotiation of the contract.
- Purchased Power expense increased $10,173,000 or 13.8% over 2012, primarily due to additional renewable energy purchases.
- Production expense increased $36,565,000 or 16.0% over 2012, primarily due to higher operations and maintenance expenses incurred at FCS.
- Transmission expense increased $2,014,000 or 9.2% over 2012, primarily due to higher transmission and regulatory expenses and fees.
- Distribution expense increased $7,107,000 or 19.2% over 2012, primarily due to additional charges for supporting services.
- Customer Accounts expense increased $1,216,000 or 8.7% over 2012, primarily due to additional credit card processing fees and postage expenses.
- Customer Service and Information expense decreased $1,234,000 or 7.5% from 2012, primarily due to decreased incentive payments for sustainability projects.

- Administration and General expense decreased $8,786,000 or 6.2% from 2012, primarily due to lower employee benefit costs.
- Depreciation and Amortization increased $1,613,000 or 1.3% over 2012, due to additional depreciation for capital additions.
- Payments in Lieu of Taxes expense increased $1,733,000 or 5.8% over 2012, due to higher retail revenues.

Other Income (Expenses)

Other income (expenses) totaled $20,956,000 in 2013, a decrease of $7,462,000 from 2012 other income (expenses) of $28,418,000. Other - net was $4,131,000 lower in 2013, primarily due to grants from the Federal Emergency Management Agency in 2012. Investment income was $2,380,000 lower than 2012 investment income of $2,041,000 due to an overall decrease in the fair market value of fixed income investments. Long-term interest rates have been rising resulting in lower bond prices and yields.

Allowances for Funds Used During Construction (AFUDC) totaled $13,334,000 in 2013, a decrease of $900,000 from 2012 AFUDC of $14,234,000 due to a lower interest rate.

A variety of products and services are offered, which provide value both to the customer and the Company. These products include Residential and Commercial Surge Protection, In-Home Electrical Protection Plan, ECO 24/7, Energy Information Services and Geothermal Loop Heat Exchanges. Offering these products and services provides opportunities to build strong relationships with customers by helping them efficiently and economically meet their energy needs.

Income from products and services was $3,228,000 for 2013, a decrease of $51,000 from 2012 income from products and services of $3,279,000. This decrease was primarily due to less income from the sale of Geothermal Loop Heat Exchange products.

Interest Expense

Interest expense was $97,555,000 for 2013, an increase of $4,930,000 over 2012 interest expense of $92,625,000. This increase was due to incurring a full year of interest expense for the 2012 Series A Electric System Revenue Bonds in 2013.

Net Income

Net income, after revenue adjustments for changes to the Debt Retirement Reserve, was $55,276,000 and $54,829,000 for 2013 and 2012, respectively. Changes to the Debt Retirement Reserve resulted in operating revenues and net income increasing by $17,000,000 in 2013 and 2012.

CAPITAL PROGRAM

The Company's utility plant assets include production, transmission and distribution, and general plant facilities. The following table summarizes the balance of capital assets as of December 31 (in thousands).

	2013	2012
Electric plant	$4,782,357	$4,692,215
Construction work in progress	404,042	394,415
Nuclear fuel - at amortized cost	101,769	100,765
Accumulated depreciation and amortization	(1,929,027)	(1,844,664)
Total utility plant - net	$3,359,141	$3,342,731

Electric system requirements, including the identification of future capital investments, are routinely evaluated to ensure current and future load requirements are serviced by a reliable and diverse power supply. Capital investments are financed with revenues from operations, bond proceeds, investment income and cash on hand. Certain capital expenditures were deferred, where possible, due to the FCS outage which concluded in 2013. Capital expenditures were $6,905,000 under budget for 2013.

The following table shows actual capital program expenditures, including allowances for funds used during construction, for the last two years and budgeted expenditures for 2014 (in thousands).

	Budget	Actual	
Capital Program	**2014**	**2013**	**2012**
Production	$ 72,746	$ 83,504	$ 89,537
Transmission and distribution	85,138	54,503	74,011
General	15,238	21,069	16,640
Total	$173,122	$159,076	$180,188

Production expenditures include equipment to comply with increasing environmental regulations. A natural gas pipeline and other equipment will be placed in service in 2014 at the Nebraska City Station to allow the use of natural gas as an alternative to fuel oil for a start-up and stabilization fuel source.

Transmission and distribution expenditures include the installation of new technologies and substation and distribution facilities to maintain system reliability, enhance efficiency and respond to load growth.

General plant expenditures include the purchase of construction and transportation equipment and information technology upgrades.

Significant capital projects planned for 2014, ordered by highest planned expenditures, include the following.

- Customer substation work – This is a project to support work being completed at Offutt Air Force Base.
- Fort Calhoun Station Remote Spent Fuel Pool Monitoring – This project will ensure continuous power at the station during extreme natural events.
- Fort Calhoun Station Security Force on Force structure improvements – This project will reinforce the physical protection of the plant.
- Fort Calhoun Station Internal Containment Structure beam reinforcements – This is the design of additional reinforcements prescribed by the Nuclear Regulatory Commission (NRC) to ensure the facility is protected against a catastrophic natural disaster.
- Distribution work – This is to support the business needs of a customer.
- Construction Equipment and Heavy Truck Replacement – This is normal replacement of general construction equipment.
- Sarpy County Station Unit No. 3 Overhaul – This is the overhaul of a gas unit at the station.

CASH AND LIQUIDITY

Cash Flows

There were increases in cash of $32,366,000 and $29,825,000 during 2013 and 2012, respectively. The following table illustrates the cash flows by activities for the years ended December 31 (in thousands).

Cash Flows	2013	2012
Cash Flows from Operating Activities	$ 168,708	$ 151,733
Cash Flows from Capital and Related Financing Activities	(274,163)	(8,072)
Cash Flows from Investing Activities	137,821	(113,836)
Change in Cash and Cash Equivalents	$ 32,366	$ 29,825

Cash flows from operating activities consist of transactions involving changes in current assets, current liabilities and other transactions that affect operating income.

- Cash flows for 2013 increased $16,975,000 over 2012, primarily due to an increase in cash received from retail customers and insurance companies. This was partially offset by an increase in cash paid to off-system counterparties for additional wind energy.

Cash flows from capital and related financing activities consist of transactions involving long-term debt and the acquisition and construction of capital assets.

- Cash flows used for 2013 increased $266,091,000 over 2012, primarily due to proceeds from long-term borrowings in 2012 which reduced the cash flows used in 2012.

Cash flows from investing activities consist of transactions involving purchases and maturities of investment securities and investment income.

- Cash flows for 2013 increased $251,657,000 over 2012, primarily due to more maturities and sales of investments than purchases in 2013.

Financing

Sufficient liquidity is maintained to ensure working capital is available for normal operational needs and unexpected but predictable risk events. OPPD's liquidity includes cash, marketable securities and a line of credit. Bond offerings also provide a significant source of liquidity for capital investments not funded by revenues from operations.

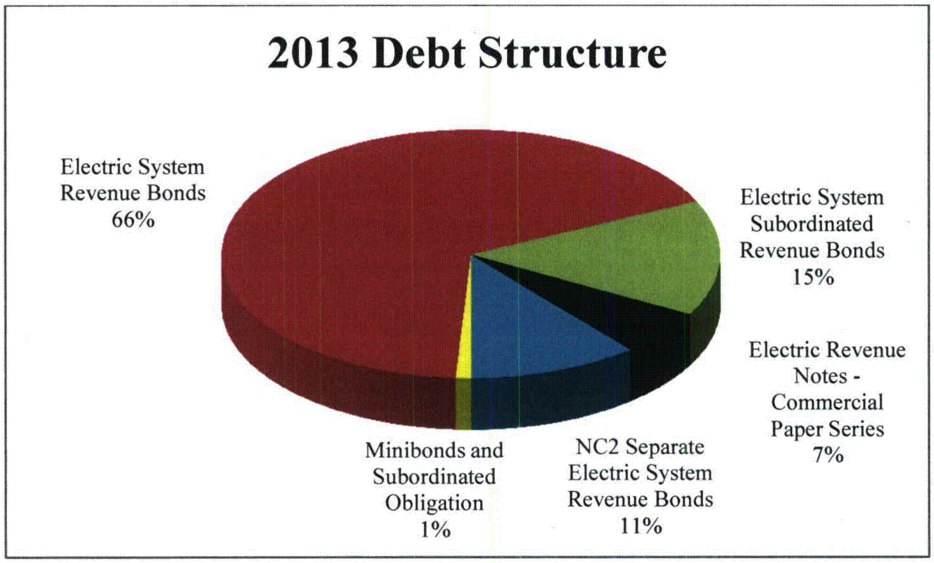
The financing plan optimizes the debt structure to ensure capital needs are financed, liquidity needs are achieved and the Company's strong financial position is maintained. The 2014 financing plan does not include any bond issues; however, the Company will continue to monitor refunding opportunities to achieve any potential interest cost savings for customer-owners.

There were no bond issuances in 2013. The Company made repayments of $26,125,000 of Electric System Revenue Bonds and $169,000 of Minibonds during 2013. Repayments for the Electric System Revenue Bonds included a principal payment of $9,385,000 for the early call of a portion of the 1993 Series C term bonds due February 1, 2014.

Two Electric System Revenue Bond issues totaling $499,370,000 were completed during 2012. An issue totaling $226,715,000 was used to refund outstanding bonds with higher interest rates, and a second issue totaling $272,655,000 was used to finance capital expenditures. In addition, repayments of $52,460,000 of Electric System Revenue Bonds, $460,000 of Electric System Subordinated Revenue Bonds and $143,000 of Minibonds were made in 2012. Repayments for the Electric System Revenue Bonds included principal payments of $8,850,000 for the early call of a portion of the 1993 Series C term bonds due February 1, 2013 and $13,990,000 for the early redemption of the 2002 Series B serial bonds due February 1, 2013.

The Company renewed a Credit Agreement for $250,000,000 in 2013. This supports the Commercial Paper Program in addition to providing another source of working capital, if needed. There were no amounts outstanding under this Credit Agreement as of December 31, 2013 or 2012. There was $150,000,000 of commercial paper outstanding as of December 31, 2013 and 2012.

The following chart illustrates the debt structure and percentage of the total as of December 31, 2013.



Debt Service Coverage for Electric System Revenue Bonds

Debt service coverage for the Electric System Revenue Bonds was 2.25 and 2.21 in 2013 and 2012, respectively. OPPD's senior lien bond indenture provides that additional bonds may not be issued unless estimated net receipts for each future year shall equal or exceed 1.4 times the debt service on all Electric System Revenue Bonds outstanding, including the additional bonds being issued. Transactions in 2013 and 2012 for the NC2 Separate Electric System were not included in the calculation because the Electric System Revenue Bonds are not secured by the Separate System. The Company is in compliance with all debt covenants.

Debt Ratio

The debt ratio is a measure of financial solvency and represents the share of debt to total capitalization (debt and net position). This ratio does not include the NC2 Separate Electric System Revenue Bonds since this debt is secured by revenues of the NC2 Participation Power Agreements. The debt ratio was 52.0% and 53.1% as of December 31, 2013 and 2012, respectively.

Ratings

High credit ratings allow the Company to borrow funds at more favorable interest rates. Both quantitative (financial strength) and qualitative (business and operating characteristics) factors are considered by the credit rating agencies in establishing a company's credit rating. The ratings received from Standard & Poor's Ratings Services (S&P) and Moody's Investors Service (Moody's), independent bond rating agencies for the latest bond issues, were among the highest ratings granted to electric utilities and confirm the agencies' assessment of the Company's strong ability to meet its debt service requirements. Moody's changed its ratings for OPPD's senior lien debt from Aa1 to Aa2 and for subordinated debt from Aa2 to Aa3, primarily due to FCS challenges and potential environmental

compliance costs for the fossil stations. Both Moody's and S&P have stable outlooks for OPPD's credit ratings.

The following table summarizes credit ratings in effect on December 31, 2013.

	S&P	Moody's
Electric System Revenue Bonds	AA	Aa2
Electric System Subordinated Revenue Bonds (including PIBs) *	AA-	Aa3
Electric Revenue Notes - Commercial Paper Series	A-1+	P-1
Minibonds *	AA-	Aa3
NC2 Separate Electric System Revenue Bonds (2005A, 2006A) *	A	A1
NC2 Separate Electric System Revenue Bonds (2008A)	A	A1

* *Payment of the principal and interest on the Electric System Subordinated Revenue Bonds, Minibonds and NC2 Separate Electric System Revenue Bonds 2005 Series A and 2006 Series A, when due, is insured by financial guaranty bond insurance policies. PIBs are Periodically Issued Bonds, which are another type of Electric System Subordinated Revenue Bond.*

RISK MANAGEMENT

Risk Management Practices

An Enterprise Risk Management (ERM) program is used to identify, quantify, prioritize and manage the risks of the Company. Specific risk-mitigation plans and procedures are maintained to provide focused and consistent efforts to mitigate various risk exposures. Several cross-functional risk committees are utilized to discuss and analyze potential risks that could hinder the achievement of OPPD's strategic objectives. Additionally, an Executive ERM Committee has been established to specifically discuss risk-related issues at the senior management level of the Company. An overview of the ERM program is provided to the Board of Directors annually.

Power marketing and fuel purchase activities are conducted within the normal course of business. Risks associated with power marketing and fuel contracting are managed within a risk management control framework. Fuel expense represents a significant portion of generation costs and affects the ability to generate and market competitively priced power. A risk-management working group is responsible for identifying, measuring and mitigating various risk exposures related to power marketing and fuel purchase activities.

OPPD participates in the wholesale marketplace with other electric utilities and power marketers for off-system energy sales. The Company must be able to offer energy at competitive prices and obtain transmission services to successfully compete in this market. Energy market prices may fluctuate substantially in a short period of time due to changes in the supply and demand of electricity. Counterparty credit risks are monitored closely on an ongoing basis. The Company's energy trading and marketing practices and processes have been modified for the implementation of the Integrated Marketplace in the Southwest Power Pool (SPP) in 2014. The risks associated with these changes have been identified and plans have been established for their mitigation.

A Rate Stabilization Reserve was established in 1999 to assist in stabilizing retail electric rates. Funds from this reserve were used to help finance higher fuel costs and unexpected energy purchases in 2011

due to the extended outage at FCS to lessen the impact on customer-owners. The fund was replenished with FPPA recoveries and insurance proceeds in 2013 and 2012. The balance of the fund was $32,000,000 and $24,612,000 as of December 31, 2013 and 2012, respectively. The balance of the reserve was maintained at $32,000,000 as of December 31, 2013 and 2012.

A Debt Retirement Reserve was established in 2003 to assist in managing the long-term risks associated with significant capital expenditures and related debt issuances. This reserve is used to meet challenges in retiring debt and maintaining adequate debt service coverage ratios. The reserve was used to provide additional revenues and funds of $17,000,000 each in 2013 and 2012. The balance of the fund was $0 and $14,000,000 as of December 31, 2013 and 2012, respectively. The balance of the reserve was $0 and $17,000,000 as of December 31, 2013 and 2012, respectively.

The Company promotes ethical business practices and the highest standards in the reporting and disclosure of financial information. The Sarbanes-Oxley Act (Act) is intended to strengthen corporate governance of publicly traded companies. As a public utility, the Company is not required to comply with the Act, but the application of these requirements, where appropriate, ensures continued public trust in OPPD, protects the interest of its stakeholders and is a sound business practice. One of the most significant requirements of the Act pertains to management's documentation and assessment of internal controls. The Company's management assesses internal controls for significant business processes that impact financial reporting. This assessment includes documenting procedures, risks and controls for these processes and assessing the effectiveness and operation of the internal controls. In addition, the Company contracts with an independent third party to administer the receipt, communication and retention of employee concerns regarding business and financial practices.

Other Reserves

Other reserves are maintained to recognize potential liabilities that arise in the normal course of business. Additional information about other reserves follows.

- The Uncollectible Accounts Reserve is established for estimated uncollectible accounts from both retail and off-system sales. Accounts Receivable is reported net of the $1,000,000 reserve for retail sales. A $5,000,000 reserve for off-system sales was established by the Board of Directors. This reserve is separately reported as a deferred inflow on the Statement of Net Position.
- The Workers' Compensation and Public Liability Reserves are established for the estimated liability for current workers' compensation and public liability claims.
- The Incurred But Not Presented Reserve is an insurance reserve that is required by state law because the Company is self-insured for health care costs. The reserve is based on health insurance claims that have been incurred but not yet presented for payment.

REGULATORY AND ENVIRONMENTAL UPDATES

Fort Calhoun Station Update

FCS was taken out of service for a normal refueling outage in April 2011. Outage activities were suspended in June 2011 to protect facilities from rising river levels caused by the release of record amounts of water from dams along the Missouri River by the U.S. Army Corps of Engineers. The NRC placed FCS into a special category of their inspection manual, Chapter 0350, in December 2011. This chapter is for nuclear plants that are in extended shutdowns with performance issues. OPPD contracts with Exelon Generation Company, LLC, the largest operator of nuclear stations in the United States, for operational and managerial support services. FCS resumed operations on December 21, 2013, after satisfactorily completing NRC requirements and inspections.

The Board of Directors authorized management to establish a regulatory asset for certain recovery costs, with amortization over a 10-year period commencing after the resumption of operations. Qualifying recovery costs will continue to be deferred until FCS's regulatory rating is increased to a more favorable NRC regulatory category. The balance of this regulatory asset was $138,362,000 and $70,627,000 as of December 31, 2013 and 2012, respectively.

SPP Integrated Marketplace and Transmission Access

OPPD became a transmission-owning member of SPP, and all of the Company's transmission facilities were placed under the SPP open access transmission tariff on April 1, 2009. In addition to tariff administration services, SPP also provides reliability coordination services, generation reserve sharing, energy imbalance market services and transmission planning services to OPPD and SPP's other transmission-owning members.

The SPP Board of Directors approved expansion of the current real-time Energy Imbalance Market (Day 1) into a Day 2 Market. The SPP Day 2 Market, also known as the Integrated Marketplace (IM), includes Day-Ahead Markets and Real-Time Markets. It also includes Ancillary Services and Transmission Congestion Rights Markets. The IM went live on March 1, 2014. SPP is now the Consolidated Balancing Authority, relieving OPPD of these responsibilities.

The IM provides a more transparent market by which load is served by the most efficient and economical generation, while maintaining the reliability of the grid. The market mechanism rewards low cost, flexible and reliable providers of electricity. OPPD's generation is in competition with other generation owners to serve load across the SPP footprint. A cross-functional project team was launched in December 2011 to prepare for the IM. Individual task teams addressed related functional areas to ensure that systems, policies and personnel were ready for the transition and able to operate effectively in the new market.

A 180-mile 345-kilovolt power line being built by OPPD and Kansas City Power and Light (Midwest Transmission Project) will run from a substation at the Nebraska City Station to Sibley, Missouri. This

project is one of several priority projects as determined by SPP and is expected to relieve congestion on the region's transmission system; improve reliability on the nation's energy grid; and improve opportunities for wind energy distribution. The final route was selected in July of 2013 after a year-long process involving 20 public meetings. Construction is expected to begin in 2015 with a planned summer 2017 in-service date.

Renewable Capability including Purchased Power Contracts

Renewable portfolio standards are currently mandated in several states but not in Nebraska. The Board of Directors has established a proactive goal to provide 10% of retail energy from renewable sources by 2020. The percentage of renewable energy increased to 6.5% in 2013 from 5.3% in 2012 and is expected to increase to 15.1% in 2014. A purchased power contract with the Western Area Power Administration provides 86 MW of hydro power that is excluded from the goal.

The following table shows the renewable generation owned or purchased and future capability (in MW).

		Capability
OPPD Owned Generation		
	Elk City Station (landfill-gas)	6.2
	Valley Station (wind)	0.7
	Subtotal OPPD Owned Generation	6.9
Purchased Wind Generation		
	Ainsworth	10.0
	Elkhorn Ridge	25.0
	Flat Water	60.0
	Petersburg	40.5
	Broken Bow I	18.0
	Crofton Bluffs	13.6
	Subtotal Purchased Wind Generation	167.1
Total Renewable Generation as of December 31, 2013		174.0
2014 Purchased Wind Generation		
	Broken Bow II	45.0
	Prairie Breeze	200.6
	Subtotal 2014 Purchased Wind Generation	245.6
2017 Purchased Wind Generation		
	Grande Prairie	400.0
Total Expected Renewable Generation as of December 31, 2017		819.6

Environmental Matters

Environmental matters can have a significant impact on operations and financial results. OPPD complies with all applicable state and federal environmental rules and regulations. The items mentioned below include proposed, enacted or enforceable laws, rules and regulations.

The Environmental Protection Agency (EPA) finalized the Mercury and Air Toxics Standard (MATS) on December 16, 2011. Compliance with this rule will be necessary by April 16, 2015. An additional year was granted by local permitting agencies to allow for pilot testing, modeling, evaluation and to facilitate installation of pollution control equipment, if necessary. Various generation options have been modeled due to the impact of MATS and other environmental regulations. Pilot testing of Dry Sorbent Injection and Activated Carbon Injection has been conducted, and the results are being analyzed to determine the optimal generating options. The Washington D.C. Circuit Court heard challenges to the MATS rule on December 10, 2013.

The EPA published the Cross-State Air Pollution Rule (CSAPR) on August 8, 2011, to improve air quality by reducing power plant emissions contributing to ozone and fine-particle pollution in other states. Specifically, this proposal would have required significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NOx). CSAPR established a cap-and-trade system with state and unit specific allowance allocations to achieve desired emission reductions for SO_2 and NOx. Implementation of Phase I of the final rule was scheduled to begin in 2012, but the United States Court of Appeals for the District of Columbia issued an order on December 30, 2011, staying CSAPR pending judicial review. On August 21, 2012, the federal court vacated CSAPR stating the rule exceeds the statutory authority of the EPA. The U.S. Supreme Court heard oral arguments on December 10, 2013, in review of the federal court's invalidation of CSAPR. In the interim, the EPA will continue administering the Clean Air Interstate Rule (CAIR), the predecessor to CSAPR pending the promulgation of a valid replacement rule. The State of Nebraska is not covered by CAIR; therefore, OPPD remains unaffected at this time.

The EPA announced its plan to reduce carbon pollution from electric generating stations on September 20, 2013. The proposed standards are the first uniform national limits on the amount of carbon emissions that future stations will be allowed. The EPA will be engaging with states and others, including the power sector, environmental groups and the public, to identify approaches shown to reduce carbon emissions. A proposed rule for controlling carbon emissions from existing generating stations is expected in 2014 with a final rule expected in 2015. OPPD continually monitors local, state and federal agencies for rules that may change or require further reductions of emissions.

Federal Energy Legislation

The 113th Congress began its two-year legislative session in January 2013. During the previous Congress, the House of Representatives passed legislation that would block efforts by the EPA to regulate greenhouse gas emissions under the Clean Air Act. In 2012, the House of Representatives also passed legislation to block or delay other EPA regulatory proposals that are aimed primarily at fossil-fired electric generation facilities. The Senate did not pass similar legislation. Given the same

leadership, the Senate will likely continue to block similar legislation passed by the House through the end of this Congressional Legislative Session, which ends in December 2014.

Efforts on energy legislation are likely to be very limited and would focus on market-based approaches that would help create jobs and grow the economy as well as possibly addressing the issue of long-term storage of high-level nuclear waste. Energy and environmental initiatives such as carbon cap-and-trade and climate change legislation could result in substantial rate increases if enacted into law. OPPD continues to monitor the status of energy and climate-change legislation in Congress and provides input through public power industry groups and the Nebraska Congressional Delegation.

State of Nebraska Energy Legislation

The Nebraska Legislature enacted Legislative Bill 646 (L.B. 646), Change Election Provisions for Public Power Districts during the 2013 session. L.B. 646 provides that public power districts create subdivisions substantially equal in population for its board elections. OPPD was the only district affected by this change. The Board of Directors changed from three to eight distinct district subdivisions in support of this legislation. The Nebraska Power Review Board approved the amendment to OPPD's charter, and the new subdivisions were effective January 1, 2014.

The Legislature also enacted Legislative Bill 388 (L.B. 388), Change Provisions Relating to Public Power and Provide for Construction of Certain Transmission Lines in 2012. L.B. 388 provides electric transmission owners, who belong to a Regional Transmission Organization (RTO), the right of first refusal to complete transmission projects in Nebraska that have been approved by the RTO. The purpose is to clarify that public power entities in Nebraska have the first right to construct, own and maintain approved transmission lines.

The Nebraska Legislature enacted Legislative Bill 901 (L.B. 901), during the 2000 session, which implemented recommendations to determine whether retail competition would be beneficial for Nebraska ratepayers. Reports for the Governor and Legislature on the conditions in the electric industry indicating whether retail competition would be beneficial for Nebraska's citizens are prepared at the request of the Nebraska Power Review Board. All of the conditions for retail competition have not been met, based on the findings from the latest report, dated October 2010.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results could differ from those estimates.

Those judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may have a significant effect on the operation of the business and on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies has not changed.

The following is a list of accounting policies that are significant to OPPD's financial condition and results of operation and require management's most significant, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policies	**Judgments/Uncertainties Affecting Application**
Environmental Matters and Pollution Remediation Obligations	• Approved methods for cleanup • Governmental regulations and standards • Cost estimates for future remediation options
Nuclear Plant Decommissioning	• Cost estimates for future decommissioning • Availability of facilities for waste disposal • Approved methods for waste disposal • Useful life of Fort Calhoun Station
Regulatory Mechanisms and Cost Recovery	• External regulatory requirements • Anticipated future regulatory decisions and their impact
Retirement Plan and Other Post Employment Benefits	• Assumptions used in computing the actuarial liability, including expected rate of return on Plan assets • Plan design
Self-Insurance Reserves for Claims for Employee-related Healthcare Benefits, Workers Compensation and Public Liability	• Cost estimates for claims • Assumptions used in computing the liabilities
Uncollectible Accounts Reserve	• Economic conditions affecting customers • Assumptions used in computing the liabilities
Unbilled Revenue	• Estimates for customer energy use and prices
Depreciation and Amortization Rates of Assets	• Estimates for approximate useful lives

Report of Management

The management of Omaha Public Power District (OPPD) is responsible for the preparation of the following financial statements and for their integrity and objectivity. These financial statements conform to generally accepted accounting principles and, where required, include amounts which represent management's best judgments and estimates. OPPD's management also prepared the other information in this Annual Report and is responsible for its accuracy and consistency with the financial statements.

To fulfill its responsibility, management maintains strong internal controls, supported by formal policies and procedures that are communicated throughout the company. Management also maintains a staff of internal auditors who evaluate the adequacy of and investigate the adherence to these controls, policies and procedures. OPPD is committed to conducting business with integrity, in accordance with the highest ethical standards, and in compliance with all applicable laws, rules and regulations. A Code of Ethics has been adopted for the Senior Executive and Financial Officers and the Controller, stating their responsibilities and standards for professional and ethical conduct.

Our independent auditors have audited the financial statements and have rendered an unmodified opinion as to the statements' fairness of presentation, in all material respects, in conformity with accounting principles generally accepted in the United States of America. During the audit, they considered internal controls over financial reporting as required by generally accepted auditing standards.

The Board of Directors pursues its oversight with respect to OPPD's financial statements through the Audit Committee, which is comprised solely of non-management directors. The committee meets periodically with the independent auditors, internal auditors and management to ensure that all are properly discharging their responsibilities. The committee reviews the annual audit plan and any recommendations the independent auditors have related to the internal control structure. The Board of Directors, on the recommendation of the Audit Committee, engages the independent auditors who have unrestricted access to the Audit Committee.

W. Gary Gates

W. Gary Gates
President and Chief Executive Officer

Edward E. Easterlin
Vice President and Chief Financial Officer

Independent Auditors' Report

To the Board of Directors
Omaha Public Power District
Omaha, Nebraska

We have audited the accompanying financial statements of Omaha Public Power District (OPPD), which comprise the statements of net position as of December 31, 2013 and 2012, and the related statements of revenues, expenses, and changes in net position, and cash flows for the years then ended and the related notes to the financial statements, which collectively comprise OPPD's financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 these financial statements based on our audits. We conducted our audit 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 the auditor's 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, the auditor considers internal control relevant to the Company'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 Company'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 that 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 OPPD as of December 31, 2013 and 2012, 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 of America.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis on page 2 through 18 be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the 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 financial statements, and other knowledge we obtained during our audit of the 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.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Omaha, Nebraska

March 20, 2014

Statements of Net Position
as of December 31, 2013 and 2012

ASSETS	2013	2012
	(thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$ 92,852	$ 60,486
Electric system revenue fund	29,962	-
Electric system revenue bond fund	73,961	56,960
Electric system subordinated revenue bond fund	6,440	6,440
Electric system construction fund	154,981	324,191
NC2 separate electric system revenue fund	13,852	13,827
NC2 separate electric system revenue bond fund	8,592	8,555
NC2 separate electric system capital costs fund	309	3,371
Accounts receivable - net	132,972	150,599
Fossil fuels - at average cost	28,910	46,485
Materials and supplies - at average cost	126,211	109,899
Other (Note 2)	31,840	28,883
Total current assets	700,882	809,696
SPECIAL PURPOSE FUNDS - at fair value		
Electric system revenue bond fund - net of current	55,681	60,484
Segregated fund - debt retirement (Note 3)	-	14,000
Segregated fund - rate stabilization (Note 3)	32,000	24,612
Segregated fund - other (Note 3)	33,586	34,819
Decommissioning funds (Note 3)	346,118	349,724
Total special purpose funds	467,385	483,639
UTILITY PLANT - at cost		
Electric plant	5,186,399	5,086,630
Less accumulated depreciation and amortization	1,929,027	1,844,664
Electric plant - net	3,257,372	3,241,966
Nuclear fuel - at amortized cost	101,769	100,765
Total utility plant - net	3,359,141	3,342,731
OTHER LONG-TERM ASSETS (Note 2)	290,241	200,247
TOTAL ASSETS	4,817,649	4,836,313
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on refunded debt	29,191	33,000
Accumulated change in fair value of hedging derivatives (Note 7)	119	502
Total deferred outflows of resources	29,310	33,502
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,846,959	$ 4,869,815

See notes to financial statements

LIABILITIES	2013	2012
	(thousands)	
CURRENT LIABILITIES		
Electric system revenue bonds (Note 4)	**$ 30,545**	$ 26,125
Electric revenue notes - commercial paper series (Note 4)	**-**	150,000
NC2 separate electric system revenue bonds (Note 4)	**2,970**	2,865
Subordinated obligation (Note 4)	**442**	406
Accounts payable	**69,720**	91,758
Accrued payments in lieu of taxes	**30,769**	29,034
Accrued interest	**42,931**	39,366
Accrued payroll	**32,753**	31,830
NC2 participant deposits	**7,428**	8,926
Other (Note 2)	**4,847**	5,637
Total current liabilities	**222,405**	385,947
LIABILITIES PAYABLE FROM SEGREGATED FUNDS (Note 2)	**30,387**	31,684
LONG-TERM DEBT (Note 4)		
Electric system revenue bonds - net of current	**1,471,830**	1,502,375
Electric system subordinated revenue bonds	**346,270**	346,270
Electric revenue notes - commercial paper series	**150,000**	-
Minibonds	**28,495**	28,127
NC2 separate electric system revenue bonds - net of current	**236,725**	239,695
Subordinated obligation - net of current	**-**	442
Total long-term debt	**2,233,320**	2,116,909
Unamortized discounts and premiums	**95,223**	103,849
Total long-term debt - net	**2,328,543**	2,220,758
OTHER LIABILITIES		
Decommissioning costs	**346,118**	349,724
Other (Note 2)	**12,918**	13,390
Total other liabilities	**359,036**	363,114
COMMITMENTS AND CONTINGENCIES (Note 11)		
TOTAL LIABILITIES	**2,940,371**	3,001,503
DEFERRED INFLOWS OF RESOURCES		
Rate stabilization reserve (Note 6)	**32,000**	32,000
Debt retirement reserve (Note 6)	**-**	17,000
Uncollectible accounts reserve - off-system	**5,000**	5,000
Total deferred inflows of resources	**37,000**	54,000
NET POSITION		
Net investment in capital assets	**1,254,740**	1,380,992
Restricted	**39,589**	25,295
Unrestricted	**575,259**	408,025
Total net position	**1,869,588**	1,814,312
TOTAL LIABILITIES, DEFERRED INFLOWS AND NET POSITION	**$ 4,846,959**	$ 4,869,815

See notes to financial statements

Statements of Revenues, Expenses and Changes in Net Position for the Years Ended December 31, 2013 and 2012

	2013	2012
	(thousands)	
OPERATING REVENUES		
Retail sales	$ 942,291	$ 869,906
Off-system sales	118,268	123,191
Other electric revenues	29,654	54,900
Total operating revenues	1,090,213	1,047,997
OPERATING EXPENSES		
Operations and maintenance		
Fuel	215,533	236,557
Purchased power	84,139	73,966
Production	265,124	228,559
Transmission	24,010	21,996
Distribution	44,180	37,073
Customer accounts	15,165	13,949
Customer service and information	15,126	16,360
Administrative and general	132,827	141,613
Total operations and maintenance	796,104	770,073
Depreciation and amortization	130,407	128,794
Payments in lieu of taxes	31,827	30,094
Total operating expenses	958,338	928,961
OPERATING INCOME	131,875	119,036
OTHER INCOME (EXPENSES)		
Contributions in aid of construction	18,570	13,066
Reduction of plant costs recovered through contributions in aid of construction	(18,570)	(13,066)
Decommissioning funds - investment income	3,606	12,833
Decommissioning funds - reinvestment	(3,606)	(12,833)
Investment income (loss)	(339)	2,041
Allowances for funds used during construction	13,334	14,234
Products and services - net	3,228	3,279
Other - net (Note 8)	4,733	8,864
Total other income - net	20,956	28,418
INTEREST EXPENSE	97,555	92,625
NET INCOME	55,276	54,829
NET POSITION, BEGINNING OF YEAR	1,814,312	1,759,483
NET POSITION, END OF YEAR	$1,869,588	$ 1,814,312

See notes to financial statements

Statements of Cash Flows
for the Years Ended December 31, 2013 and 2012

	2013	2012
	(thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash received from retail customers	$ 939,617	$ 897,540
Cash received from off-system counterparties	108,453	107,733
Cash received from insurance companies	24,000	17,656
Cash paid to operations and maintenance suppliers	(620,474)	(626,679)
Cash paid to off-system counterparties	(82,808)	(59,940)
Cash paid to employees	(169,988)	(156,361)
Cash paid for in lieu of taxes and other taxes	(30,092)	(28,216)
Net cash provided from operating activities	168,708	151,733
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Proceeds from long-term borrowings	-	560,881
Principal reduction of debt	(29,539)	(289,085)
Interest paid on debt	(97,285)	(106,411)
Acquisition and construction of capital assets	(166,052)	(178,785)
Proceeds from NC2 participants	3,560	2,848
Contributions in aid of construction and other reimbursements	19,953	13,293
Acquisition of nuclear fuel	(4,800)	(10,813)
Net cash used for capital and related financing activities	(274,163)	(8,072)
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of investments	(531,951)	(860,586)
Maturities and sales of investments	666,793	743,528
Purchases of investments for decommissioning funds	(204,516)	(291,237)
Maturities and sales of investments in decommissioning funds	204,516	291,237
Investment income	2,979	3,222
Net cash provided from (used for) investing activities	137,821	(113,836)
CHANGE IN CASH AND CASH EQUIVALENTS	32,366	29,825
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	60,486	30,661
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 92,852	$ 60,486
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED FROM OPERATING ACTIVITIES		
Operating income	$ 131,875	$ 119,036
Adjustments to reconcile operating income to net cash provided from operating activities		
Depreciation and amortization	130,407	128,794
Amortization of nuclear fuel	564	-
Changes in assets and liabilities		
Accounts receivable	3,191	(25,849)
Fossil fuels	17,575	5,198
Materials and supplies	(16,312)	(8,289)
Regulatory asset for FPPA	(15,169)	3,237
Accounts payable	(5,436)	3,432
Accrued payments in lieu of taxes	1,735	1,878
Accrued payroll	923	2,493
Debt retirement reserve	(17,000)	(17,000)
Regulatory asset for FCS recovery costs	(67,735)	(70,627)
Other	4,090	9,430
Net cash provided from operating activities	$ 168,708	$ 151,733
NONCASH CAPITAL ACTIVITIES		
Utility plant additions from outstanding liabilities	$ 13,983	$ 30,590

See notes to financial statements

Notes to Financial Statements
as of and for the Years Ended December 31, 2013 and 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Business – The Omaha Public Power District (OPPD or Company), a political subdivision of the state of Nebraska, is a public utility engaged in the generation, transmission and distribution of electric power and energy and other related activities. The Board of Directors is authorized to establish rates. OPPD is generally not liable for federal and state income or ad valorem taxes on property; however, payments in lieu of taxes are made to various local governments.

Basis of Accounting – The financial statements are presented in accordance with generally accepted accounting principles (GAAP) for proprietary funds of governmental entities. Accounting records are maintained generally in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and all applicable pronouncements of the Governmental Accounting Standards Board (GASB).

OPPD applies the accounting policies established in the GASB Codification Section Re10, *Regulated Operations.* This guidance permits an entity with cost-based rates to include costs in a period other than the period in which the costs would be charged to expense by an unregulated entity if it is probable that these costs will be recovered through rates charged to customers. This guidance also permits an entity to defer revenues by recognizing liabilities to cover future expenditures. The guidance applies to OPPD because the rates of the Company's regulated operations are established and approved by the governing board.

If, as a result of changes in regulation or competition, the ability to recover these assets and to satisfy these liabilities would not be assured, OPPD would be required to write off or write down such regulatory assets and liabilities, unless some form of transition cost recovery continues through established rates. In addition, any impairment to the carrying costs of deregulated plant and inventory assets would be determined. There were no write-downs of regulatory assets for the years ended December 31, 2013 and 2012.

Classification of Revenues and Expenses – Revenues and expenses related to providing energy services in connection with the Company's principal ongoing operations are classified as operating. All other revenues and expenses are classified as non-operating and reported as other income (expenses) on the Statements of Revenue, Expenses and Changes in Net Position.

Revenue Recognition – Electric operating revenues are recognized as earned. Meters are read and bills are rendered on a cycle basis. Revenues earned after meters are read are estimated and accrued as unbilled revenues at the end of each accounting period.

Cash and Cash Equivalents – The operating fund account is called the Electric System Revenue Fund (Note 3). Highly liquid investments for the Electric System Revenue Fund with an original maturity of three months or less are considered to be cash equivalents. Cash and cash equivalents in the Special Purpose Funds are reported as investments.

Accounts Receivable – Accounts Receivable includes outstanding amounts from customers and an estimate for unbilled revenues. An estimate is made for the Reserve for Uncollectible Accounts for retail customers based on an analysis of Accounts Receivable and historical write-offs net of recoveries. Additional amounts may be included based on the credit risks of significant parties. Accounts Receivable includes $45,905,000 and $41,415,000 in unbilled revenues as of December 31, 2013 and 2012, respectively. Accounts Receivable was reported net of the Reserve for Uncollectible Accounts of $1,000,000 and $1,020,000 as of December 31, 2013 and 2012, respectively.

Utility Plant – Utility plant is stated at cost, which includes property additions, replacements of units of property and betterments. Maintenance and replacement of minor items are charged to operating expenses. Costs of depreciable units of electric plant retirements are eliminated from electric plant accounts by charges, less salvage plus removal expenses, to the accumulated depreciation account. Electric plant includes both tangible and intangible assets. Intangible assets include costs related to regulatory licenses, software licenses and other rights to use property. Electric plant includes construction work in progress of $404,042,000 and $394,415,000 as of December 31, 2013 and 2012, respectively.

The following table summarizes electric plant balances as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Retirements	2013
Electric plant	$ 5,086,630	$ 163,887	$ (64,118)	$ 5,186,399
Less accumulated depreciation & amortization	1,844,664	146,910	(62,547)	1,929,027
Electric plant - net	$ 3,241,966	$ 16,977	$ (1,571)	$ 3,257,372

Allowances for funds used during construction (AFUDC), approximates OPPD's current weighted average cost of debt. AFUDC was capitalized as a component of the cost of utility plant. These allowances for both construction work in progress and nuclear fuel were computed at 3.8% and 4.3% for the years ended December 31, 2013 and 2012, respectively.

The carrying amounts of long-lived assets for impairment are periodically reviewed. An asset is considered impaired when the magnitude of the decline in service utility is significant and not part of the normal life cycle of the capital asset. There were no write-downs for impairments for the years ended December 31, 2013 and 2012.

Contributions in Aid of Construction (CIAC) – Payments are received from customers for construction costs primarily relating to the expansion of the electric system. FERC guidelines are followed in recording CIAC. These guidelines direct the reduction of utility plant assets by the amount of contributions received toward the construction of utility plant. CIAC is recorded as other income and offset by an expense in the same amount representing the recovery of plant costs. This allows for compliance with GASB Codification Section N50, *Nonexchange Transactions*, while continuing to follow FERC guidelines. CIAC from participants for the capital costs of Nebraska City Station Unit 2 (NC2) was $5,091,000 and $4,725,000 for the years ended December 31, 2013 and 2012, respectively.

Depreciation and Amortization – Depreciation for assets is computed on the straight-line basis at rates based on the estimated useful lives of the various classes of property. Depreciation expense for depreciable property averaged approximately 2.8% and 2.9% for the years ended December 31, 2013 and 2012, respectively.

Amortization of nuclear fuel is based on the cost thereof, and is prorated by fuel assembly in accordance with the thermal energy that each assembly produces. Intangible assets are amortized over their expected useful life. Amortization of intangible assets, included with depreciation and amortization expense in these financial statements, was $3,508,000 and $4,669,000 for the years ended December 31, 2013 and 2012, respectively.

NC2 was placed in commercial operation in 2009. Half of the unit's output is sold under 40-year Participation Power Agreements (PPAs). Certain participants funded their share of construction costs with NC2 Separate Electric System Revenue Bonds. These participants are billed for the debt service related to these bonds. The amounts recovered for debt service for the electric plant construction and other costs are included in off-system sales revenues. The revenues related to principal repayment will equal related depreciation and other deferred NC2 expenses over the 40-year term of the PPAs. A regulatory asset was established to equate expenses and the amount included in off-system sales revenues for principal repayment in order to maintain revenue neutrality in the interim years. This regulatory asset will increase annually until 2030 when principal repayments begin exceeding depreciation and other deferred expenses. After 2030, the regulatory asset will be reduced annually by recognizing deferred depreciation and other deferred expenses until its elimination in 2049, which is the end of the initial term of the PPAs.

In 2004, the Board of Directors approved a change in the depreciation estimate for Fort Calhoun production plant assets to 2043. This estimate is ten years beyond the term of Fort Calhoun Station's (FCS) current operating license. A regulatory asset was established for the difference in depreciation expense resulting from the use of the estimated economic life of the asset versus the license term. The reduction in depreciation expense will be recorded each year as a regulatory asset in deferred charges until 2033. The regulatory asset will be reduced through the recognition of depreciation expense over the assets' remaining economic life in the years 2034 through 2043.

Nuclear Fuel Disposal Costs – Permanent disposal of spent nuclear fuel is the responsibility of the federal government under an agreement entered into with the Department of Energy (DOE). Under the agreement, there is a fee of one mill per kilowatt-hour on net electricity generated and sold from FCS. The spent nuclear fuel disposal costs are included in nuclear fuel amortization and are collected from customers as part of fuel costs. There were nuclear fuel disposal costs of $91,000 and $0 for the years ended December 31, 2013 and 2012, respectively.

The agreement required the federal government to begin accepting high-level nuclear waste by January 1998; however, the DOE does not have a storage facility. In May 1998, the United States Court of Appeals confirmed the DOE's statutory obligation to accept spent fuel by 1998, but rejected the request that a move-fuel order be issued. In March 2001, OPPD, along with a number of other utilities, filed suit against the DOE in the United States Court of Federal Claims alleging breach of contract.

In 2006, the DOE agreed to reimburse OPPD for allowable costs for managing and storing spent nuclear fuel and high-level waste incurred due to the DOE's delay in accepting waste. Applications are submitted periodically to the DOE for reimbursement of costs incurred for the storage of high-level nuclear waste and any reimbursements are included in CIAC.

Nuclear Decommissioning – The Board of Directors has approved the collection of nuclear decommissioning costs based on an independent engineering study of the costs to decommission FCS. Based on cost estimates, inflation rates and fund earnings projections, no funding has been necessary since 2001. Decommissioning funds are reported at fair value. The decommissioning cost liability is adjusted for investment income and changes in fair value, resulting in no impact on net income. Investment income was $6,477,000 and $7,534,000 for the years ended December 31, 2013 and 2012, respectively. The fair value of the decommissioning funds decreased $10,083,000 and increased $5,299,000 during 2013 and 2012, respectively. The present value of the total decommissioning cost estimate for FCS was $851,912,000 and $733,314,000 as of June 30, 2013 and 2012, respectively.

Regulatory Assets and Liabilities – Rates for regulated operations are established and approved by the Board of Directors. The provisions of GASB Codification Section Re10, *Regulated Operations,* are applied. This guidance provides that regulatory assets are rights to additional revenues or deferred expenses, which are expected to be recovered through customer rates over some future period. Regulatory liabilities are reductions in earnings (or costs recovered) to cover future expenditures.

A Major Planned Production Outage (Outage), as defined by OPPD, is an outage with incremental operations and maintenance expenses of $5,000,000 or more. These Outages are periodically completed to maintain and enhance the performance and efficiency of station operations, which benefits the station over the next operating cycle of production. In October 2013, the Board of Directors authorized regulatory accounting treatment for qualifying Outage costs to allow the use of the defer-and-amortize method. Eligible outage costs will be deferred as a regulatory asset and amortized to expense over the subsequent operating cycle. The first outage that will qualify for this regulatory accounting treatment is at FCS. Pre-outage costs are expected to be deferred commencing in 2015.

A Fuel and Purchased Power Adjustment (FPPA) was implemented in the retail rate structure in 2010. The Board of Directors authorized the use of regulatory accounting to maintain revenue neutrality by matching retail revenues attributed to fuel and purchased power costs with the actual costs incurred. Additional fuel and purchased power expenses were incurred as a result of the extended outage at FCS. This resulted in FPPA under-recoveries of $35,124,000 and $45,375,000 for the years ended December 31, 2013 and 2012, respectively. The FPPA regulatory assets were reduced for customer collections of $19,955,000 and $11,969,000 in 2013 and 2012, respectively. FCS outage insurance recoveries of $36,643,000 further reduced this regulatory asset in 2012.

The Regulatory Asset for FPPA, included in Other Current Assets, was $23,020,000 and $19,955,000 as of December 31, 2013 and 2012, respectively (Note 2). The Regulatory Asset for FPPA, included in Other Long-Term Assets, was $24,526,000 and $12,422,000 as of December 31, 2013 and 2012, respectively (Note 2). This regulatory asset represented the rights to additional revenues based on incurred expenses due to under-recoveries of fuel and purchased power costs.

Additional regulatory assets included in Other Long-Term Assets consist of deferred financing costs and other deferred expenses for FCS and NC2. In 2004, the Board of Directors approved a change in the depreciation estimate for FCS production assets to 2043. This estimate is ten years beyond the term of the current operating license. NC2 was placed in commercial operation in 2009. As previously noted, certain NC2 expenses were deferred to maintain revenue neutrality from transactions with participants who funded their share of construction costs with NC2 Separate Electric System Revenue Bonds.

The Board of Directors authorized the use of regulatory accounting for debt issuance costs in 2012 because of new accounting standards which would have required these costs to be expensed in the period incurred. These costs are amortized over the life of the associated bond issues consistent with the rate methodology. The Board of Directors also authorized the use of regulatory accounting in 2012 for significant, unplanned operations and maintenance costs at FCS incurred to address concerns from the Nuclear Regulatory Commission (NRC) and enhance operations. These costs will be amortized over a ten-year period which commenced in December 2013 with FCS's return to service.

The following table summarizes the balances of the Regulatory Assets as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Reductions	2013
Regulatory asset for FCS - Recovery Costs	$ 70,627	$ 68,811	$ (1,076)	$ 138,362
Regulatory asset for FCS - depreciation	54,705	6,485	-	61,190
Regulatory asset for NC2	37,067	4,190	-	41,257
Regulatory asset for FPPA	32,377	35,124	(19,955)	47,546
Regulatory asset for financing costs	17,266	-	(979)	16,287
	$ 212,042	$ 114,610	$ (22,010)	$ 304,642

Regulatory liabilities, which are deferred inflows of resources, consist of reserves for debt retirement, rate stabilization and uncollectible accounts from off-system sales. The Debt Retirement Reserve was established for the retirement of outstanding debt and to help maintain debt service coverage ratios at appropriate levels (Note 6). The Rate Stabilization Reserve was established to help maintain stability in OPPD's long-term rate structure (Note 6). The Uncollectible Accounts Reserve - Off-System was established to recognize a loss contingency for uncollectible accounts from off-system sales customers based on the greater of $5,000,000 or an estimate (as defined) considering the previous year's accounts receivable balances for off-system sales customers.

The following table summarizes the balances of the Regulatory Liabilities as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Reductions	2013
Rate stabilization reserve	$ 32,000	$ -	$ -	$ 32,000
Debt retirement reserve	17,000	-	(17,000)	-
Uncollectible accounts reserve - off-system	5,000	-	-	5,000
	$ 54,000	$ -	$ (17,000)	$ 37,000

Natural Gas Inventories and Contracts – Natural gas inventories are maintained for the Cass County Station. The weighted average cost of natural gas consumed is used to expense natural gas from inventories. OPPD is exposed to market price fluctuations on its purchases of natural gas. The Company may enter into futures contracts and purchase options to manage the risk of volatility in the market price of gas on anticipated purchase transactions (Note 7).

Net Position – Net Position is reported in three separate components on the Statement of Net Position. Net Investment in Capital Assets is the net position share attributable to net utility plant assets reduced by outstanding related debt. Restricted is the share of net position that has usage restraints imposed by law or by debt covenants, such as certain revenue bond funds and segregated funds, net of related liabilities. Unrestricted is the share of net position that is neither restricted nor invested in capital assets.

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.

Recent Accounting Pronouncements – In June 2012, GASB issued Statement No. 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27*. The objective of this statement is to improve accounting and financial reporting for pensions. This statement requires governments to more comprehensively and comparably measure the annual costs of pension benefits. This statement also enhances accountability and transparency through revised and new note disclosures and required supplementary information. This statement is effective for reporting periods beginning after June 15, 2014. This statement will be implemented in 2015. The implementation of this statement will result in the recognition of a net pension liability for the statement of net position, a change in the pension expense calculation for the statement of revenues, expenses and changes in net position and additional note disclosures and required supplementary information.

In November 2013, GASB issued Statement No. 71, *Pension Transition for Contributions Made Subsequent to the Measurement Date – an amendment of GASB Statement No. 68*. The objective of this statement is to clarify accounting and financial reporting for pensions. This statement requires governments to recognize a beginning deferred outflow of resources for pension contributions made subsequent to the measurement date of the beginning net pension liability calculated under GASB Statement No. 68. This statement is effective for reporting periods beginning after June 15, 2014 and will be applied simultaneously with GASB Statement No. 68 in 2015.

2. ASSETS AND LIABILITIES DETAIL BALANCES

Other Current Assets

The composition as of December 31 was as follows (in thousands):

	2013	2012
Regulatory asset for FPPA	$ 23,020	$ 19,955
Prepayments	5,475	4,948
Sulfur dioxide allowance inventory	2,841	2,799
Interest receivable	375	642
Commodity derivative instruments (Note 7)	53	416
Other	76	123
Total	$ 31,840	$ 28,883

Other Long-Term Assets

The composition as of December 31 was as follows (in thousands):

	2013	2012
Regulatory asset for FCS - Recovery Costs	$ 138,362	$ 70,627
Regulatory asset for FCS - depreciation	61,190	54,705
Regulatory asset for NC2	41,257	37,067
Regulatory asset for FPPA	24,526	12,422
Regulatory asset for financing costs	16,287	17,266
Deposit with SPP	2,000	-
Sulfur dioxide allowance inventory	-	1,625
Other	6,619	6,535
Total	$ 290,241	$ 200,247

Other Current Liabilities

The composition as of December 31 was as follows (in thousands):

	2013	2012
Unearned revenues	$ 3,310	$ 2,441
Deposits	1,022	804
Payroll taxes and other employee liabilities	475	1,963
Other	40	429
Total	$ 4,847	$ 5,637

Liabilities Payable from Segregated Funds

The composition as of December 31 was as follows (in thousands):

	2013	2012
Customer deposits	$ 22,673	$ 24,293
Customer advances for construction	3,342	3,413
Incurred but not presented reserve	2,374	2,310
Other	1,998	1,668
Total	$ 30,387	$ 31,684

Other Liabilities

The composition as of December 31 was as follows (in thousands):

	2013	2012
Unearned revenues	$ 8,757	$ 9,219
Capital purchase agreement	1,951	2,175
Workers' compensation reserve	1,558	1,344
Public liability reserve	190	199
Other	462	453
Total	$ 12,918	$ 13,390

3. FUNDS AND INVESTMENTS

Funds of OPPD were as follows:

Electric System Revenue Fund and NC2 Separate Electric System Revenue Fund – These funds are to be used for operating activities for their respective electric system. Cash and cash equivalents in the Electric System Revenue Fund are shown separately from investments on the Statement of Net Position.

Electric System Revenue Bond Fund, Electric System Subordinated Revenue Bond Fund and NC2 Separate Electric System Revenue Bond Fund – These funds are to be used for the retirement of their respective revenue bonds and the payment of the related interest and reserves as required. Investments with maturity dates within the next year are designated as current.

Electric System Construction Fund and NC2 Separate Electric System Capital Costs Fund – These funds are to be used for capital improvements, additions and betterments to and extensions of their respective electric system.

Segregated Fund – Debt Retirement – This fund is to be used for the retirement of outstanding debt and to assist in maintaining debt service coverage ratios at appropriate levels. Since there is no funding requirement for the Debt Retirement Reserve, this fund also may be used to provide additional liquidity for operations as necessary. The balance of the Debt Retirement Fund was $0 and $14,000,000 as of December 31, 2013 and 2012, respectively.

Segregated Fund – Rate Stabilization – This fund is to be used to help stabilize rates through the transfer of funds to operations as necessary. Since there is no funding requirement for the Rate

Stabilization Reserve, this fund also may be used to provide additional liquidity for operations as necessary. This fund was used to help finance the higher fuel costs and unexpected energy purchases in 2011. Proceeds from the FCS outage insurance and customer collections for prior year FPPA under-recoveries were used to replenish this fund in 2013 and 2012. The balance of the Rate Stabilization Fund was $32,000,000 and $24,612,000 as of December 31, 2013 and 2012, respectively.

Segregated Fund – Other – This fund represents assets held for payment of customer deposits, refundable advances, certain other liabilities and funds set aside for terminal removal costs for NC2 and OPPD's self-insured health insurance plans (Note 5).

The following table summarizes the balances of the segregated funds as of December 31 (in thousands).

	2013	2012
Segregated Fund - self-insurance	$ 5,135	$ 5,106
Segregated Fund - other	28,451	29,713
Total	$ 33,586	$ 34,819

Decommissioning Funds – These funds are for the costs to decommission FCS when its operating license expires. The Decommissioning Funds are held by an outside trustee in compliance with the decommissioning funding plans approved by the Board of Directors. The 1990 Plan was established in accordance with NRC regulations for the purpose of discharging the obligation to decommission FCS. The 1992 Plan was established to retain funds in excess of NRC minimum funding requirements based on an independent engineering study which indicated that decommissioning costs would exceed the NRC minimum requirements.

The following table summarizes the balances of the decommissioning funds as of December 31 (in thousands).

	2013	2012
Decommissioning Trust - 1990 Plan	$ 264,758	$ 267,278
Decommissioning Trust - 1992 Plan	81,360	82,446
Total	$ 346,118	$ 349,724

Fair Value of Investments – These values were determined based on quotes received from trustees' market valuation services.

The following table summarizes OPPD's investments as of December 31 (in thousands). The weighted average maturity was based on the face value for investments.

	2013		2012	
		Weighted Average		Weighted Average
Investment Type	**Fair Value**	**Maturity (Years)**	**Fair Value**	**Maturity (Years)**
Commercial paper	$ 52,425	0.5	$ -	-
Money market	1,160	-	25,825	-
Mutual funds	183,960	-	186,842	-
U.S. agencies	352,127	1.5	538,450	1.4
U.S. treasuries	65,414	3.3	126,902	2.2
Corporate bonds	23,645	2.5	18,548	3.3
World bank security notes	76,314	0.1	-	-
Total	$ 755,045		$ 896,567	
Portfolio weighted average maturity		1.2		1.2

Interest Rate Risk – The investment in relatively short-term securities reduces interest rate risk, as evidenced by its portfolio weighted average maturity of 1.2 years as of December 31, 2013 and 2012. In addition, OPPD is a buy-and-hold investor, which minimizes interest rate risk.

Credit Risk – The investment policy is to comply with bond covenants and state statutes for governmental entities, which limit investments to investment-grade fixed income obligations. OPPD was in full compliance with bond covenants and state statutes as of December 31, 2013 and 2012.

Custodial Credit Risk – Bank deposits were entirely insured or collateralized with securities held by OPPD or by its agent in OPPD's name at December 31, 2013 and 2012. All investment securities are delivered under contractual trust agreements.

4. DEBT

The proceeds of debt issued are utilized primarily to finance the construction program.

The following table summarizes the debt balances as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Retirements	2013
Electric system revenue bonds	$ 1,528,500	$ -	$ (26,125)	$ 1,502,375
Electric system subordinated revenue bonds	346,270	-	-	346,270
Electric revenue notes - commercial paper series	150,000	-	-	150,000
Minibonds	28,127	537	(169)	28,495
NC2 separate electric system revenue bonds	242,560	-	(2,865)	239,695
Subordinated obligation	848	-	(406)	442
Total	$ 2,296,305	$ 537	$ (29,565)	$ 2,267,277

Lien Structure – In the event of a default, subject to the terms and conditions of debt covenants, OPPD is required to satisfy all Electric System Revenue Bond obligations before paying second-tier bonds and notes which are Electric System Subordinated Revenue Bonds, Electric Revenue Notes – Commercial Paper Series and Minibonds. OPPD will pay the Subordinated Obligation after second-tier debt.

Electric System Revenue Bonds – These bonds are payable from and secured by a pledge of and lien upon the revenues of the Electric System, subject to the prior payment therefrom of the operations and maintenance expenses of the Electric System. The Electric System Revenue Bonds are Senior Bonds.

Moody's Investors Service and Standard & Poor's Rating Services rated the Electric System Revenue Bonds as Aa2 and AA in 2013 and Aa1 and AA in 2012.

The following table summarizes outstanding Electric System Revenue Bonds as of December 31, 2013, (in thousands).

Issue	Maturity Dates	Type	Interest Rates	Amount
1993 Series C	2014	Term	5.5%	$ 9,385
2005 Series B	2017 - 2022	Serial	5.0%	17,740
2007 Series A	2018 - 2027	Serial	4.0% - 5.0%	108,705
2007 Series A	2029 - 2043	Term	4.75% - 5.0%	136,295
2008 Series A	2018 - 2028	Serial	4.6% - 5.5%	34,710
2008 Series A	2029 - 2039	Term	5.5%	70,290
2009 Series A	2023 - 2029	Serial	4.0% - 4.75%	25,700
2009 Series A	2030 - 2039	Term	5.0%	59,300
2010 Series A	2022 - 2041	Term	5.431%	120,000
2011 Series A	2014 - 2024	Serial	3.0% - 5.0%	143,375
2011 Series B	2023 - 2029	Serial	3.25% - 5.0%	34,570
2011 Series B	2031 - 2042	Term	4.0% - 5.0%	103,360
2011 Series C	2014 - 2030	Serial	2.5% - 5.0%	139,575
2012 Series A	2023 - 2034	Serial	4.0% - 5.0%	139,480
2012 Series A	2035 - 2042	Term	5.0%	133,175
2012 Series B	2017 - 2034	Serial	3.0% - 5.0%	141,295
2012 Series B	2038 - 2046	Term	3.75% - 5.0%	85,420
Total				$ 1,502,375

The following table summarizes outstanding Electric System Revenue Bonds as of December 31, 2012 (in thousands).

Issue	Maturity Dates	Type	Interest Rates	Amount
1993 Series C	2013 - 2014	Term	5.5%	$ 27,620
2003 Series A	2013	Serial	3.8%	7,000
2005 Series B	2017 - 2022	Serial	5.0%	17,740
2007 Series A	2018 - 2027	Serial	4.0% - 5.0%	108,705
2007 Series A	2029 - 2043	Term	4.75% - 5.0%	136,295
2008 Series A	2018 - 2028	Serial	4.6% - 5.5%	34,710
2008 Series A	2029 - 2039	Term	5.5%	70,290
2009 Series A	2023 - 2029	Serial	4.0% - 4.75%	25,700
2009 Series A	2030 - 2039	Term	5.0%	59,300
2010 Series A	2022 - 2041	Term	5.431%	120,000
2011 Series A	2014 - 2024	Serial	3.0% - 5.0%	143,375
2011 Series B	2023 - 2029	Serial	3.25% - 5.0%	34,570
2011 Series B	2031 - 2042	Term	4.0% - 5.0%	103,360
2011 Series C	2013 - 2030	Serial	2.0% - 5.0%	140,465
2012 Series A	2023 - 2034	Serial	4.0% - 5.0%	139,480
2012 Series A	2035 - 2042	Term	5.0%	133,175
2012 Series B	2017 - 2034	Serial	3.0% - 5.0%	141,295
2012 Series B	2038 - 2046	Term	3.75% - 5.0%	85,420
Total				$ 1,528,500

On February 1, 2013, a principal payment of $16,740,000 was made for the Electric System Revenue Bonds. On August 1, 2013, a principal payment of $9,385,000 was made for the call of the 1993 Series C term bonds due February 1, 2014. Term bonds are subject to call every six months.

On February 1, 2012, a principal payment of $29,620,000 was made for the Electric System Revenue Bonds. On August 1, 2012, a principal payment of $8,850,000 was made for the call of the 1993 Series C term bonds due February 1, 2013. Term bonds are subject to call every six months. On November 1, 2012, a principal payment of $13,990,000 was made for the call of the 2002 Series B Electric System Revenue Bonds due on February 1, 2013. On October 10, 2012, OPPD issued 2012 Series A Electric System Revenue Bonds and Series B Electric System Revenue Bonds. The 2012 Series B Electric System Revenue Bonds were used for the refunding of portions of the 2005 Series B and 2006 Series A Bonds. The refunding reduced total debt service payments over the life of the bonds by $39,963,000 and resulted in an economic gain (difference between the present values of the old and new debt service payments) of $25,357,000.

Electric System Revenue Bonds, from the following series, with outstanding principal amounts of $325,780,000 as of December 31, 2013, were legally defeased: 1986 Series A, 1992 Series B, 1993 Series B, 2005 Series B and 2006 Series A. Electric System Revenue Bonds, from the following series, with outstanding principal amounts of $426,125,000 as of December 31, 2012, were legally defeased: 1986 Series A, 1992 Series B, 1993 Series B, 2003 Series A, 2005 Series B and 2006 Series

A. Defeased bonds are funded by government securities in irrevocable escrow accounts. Accordingly, the bonds and the related government securities escrow accounts are not included in the Statement of Net Position.

OPPD's bond indenture, amended effective March 4, 2009, provides for certain restrictions, the most significant of which are:

- Additional bonds may not be issued unless estimated net receipts (as defined) for each future year equal or exceed 1.4 times the debt service on all Electric System Revenue Bonds outstanding, including the additional bonds being issued or to be issued in the case of a power plant (as defined) being financed in increments.

- The Electric System is required to be maintained by the Company in good condition.

The following table summarizes Electric System Revenue Bond payments (in thousands).

	Principal	Interest
2014	$ 30,545	$ 70,994
2015	40,465	69,448
2016	43,065	67,573
2017	45,900	65,636
2018	47,815	63,656
2019 - 2023	221,415	286,224
2024 - 2028	228,470	233,860
2029 - 2033	274,910	172,945
2034 - 2038	273,620	109,117
2039 - 2043	239,870	34,139
2044 - 2046	56,300	3,533
Total	$ 1,502,375	$ 1,177,125

The average interest rate for Electric System Revenue Bonds was 4.8% for the years ended December 31, 2013 and 2012.

Electric System Subordinated Revenue Bonds – These bonds are payable from and secured by a pledge of revenues of the Electric System, subject to the prior payment of the operations and maintenance expenses of the Electric System and the prior payment of the Electric System Revenue Bonds. The payment of the principal and interest on these bonds is insured by a municipal bond insurance policy.

The Electric System Subordinated Revenue Bonds include Periodically Issued Bonds (PIBs). Certain issues of the PIBs may be redeemed prior to maturity upon the death of the holder subject to certain conditions as outlined in the offering document.

The following table summarizes Electric System Subordinated Revenue Bonds (PIBs) payments (in thousands).

	Principal	Interest
2014	$ -	$ 6,540
2015	-	6,540
2016	-	6,540
2017	-	6,540
2018	-	6,541
2019-2023	-	32,701
2024-2028	-	32,701
2029-2033	-	32,702
2034-2038	74,230	24,451
2039-2042	72,040	8,207
Total	$ 146,270	$ 163,463

The following table summarizes Electric System Subordinated Revenue Bond payments for the 2007 Series AA (in thousands).

	Principal	Interest
2014	$ -	$ 8,901
2015	-	8,902
2016	-	8,902
2017	-	8,902
2018	1,000	8,882
2019-2023	8,000	43,763
2024-2028	42,000	38,994
2029-2033	67,000	27,171
2034-2038	82,000	8,955
Total	$ 200,000	$ 163,372

The average interest rate for the Electric System Subordinated Revenue Bonds (PIBs and the 2007 Series AA) was 4.5% for the years ended December 31, 2013 and 2012.

Electric Revenue Notes - Commercial Paper Series – The outstanding balance of Commercial Paper was $150,000,000 as of December 31, 2013 and 2012. The average borrowing rates were 0.1% and 0.2% for the years ended December 31, 2013 and 2012, respectively. A Credit Agreement with Bank of America, N.A., includes a covenant to retain drawing capacity at least equal to the issued and outstanding amount of Commercial Paper Notes.

Minibonds – Minibonds consist of current interest-bearing and capital appreciation minibonds. The minibonds may be redeemed prior to their maturity dates at the request of a holder, subject to certain conditions as outlined in the Minibond Official Statement. There were no Minibond maturities in 2013 other than redemptions for the annual put option. The average interest rates were 5.05% for the years ended December 31, 2013 and 2012. The principal and interest on these bonds is insured by a municipal bond insurance policy.

The following table summarizes outstanding minibond balances at December 31 (in thousands).

Principal	**2013**	**2012**
2001 Minibonds, due 2021 (5.05%)	$ 23,460	$ 23,604
Accreted interest on capital appreciation minibonds	5,035	4,523
Total	$ 28,495	$ 28,127

Subordinated Obligation – The subordinated obligation is payable in annual installments of $482,000, which includes interest at 9.0%, through 2014.

Credit Agreements – OPPD has a Credit Agreement with the Bank of America, N.A., for $250,000,000 which will expire on October 1, 2015. The Credit Agreement includes a covenant to retain drawing capacity at least equal to the issued and outstanding amount of Commercial Paper Notes. The Company is in compliance with the Credit Agreement covenants. There were no amounts outstanding under this Credit Agreement as of December 31, 2013 and 2012.

NC2 Separate Electric System Revenue Bonds – Participation Power Agreements were executed with seven public power and municipal utilities for half of the output of NC2. The participants' rights to receive, and obligations to pay costs related to, half of the output is the "Separate System."

The following table summarizes NC2 Separate Electric System Revenue Bond payments (in thousands).

	Principal	**Interest**
2014	$ 2,970	$ 11,498
2015	3,080	11,381
2016	3,200	11,258
2017	3,330	11,128
2018	3,460	10,989
2019-2023	19,635	52,549
2024-2028	24,455	47,584
2029-2033	30,860	41,013
2034-2038	39,090	32,554
2039-2043	44,415	21,945
2044-2048	54,950	9,685
2049	10,250	256
Total	$ 239,695	$ 261,840

The payment of principal and interest on the 2005 Series A and 2006 Series A Bonds is insured by municipal bond insurance policies. The average interest rate for NC2 Separate Electric System Revenue Bonds was 4.8% for the years ended December 31, 2013 and 2012.

Fair Value Disclosure – The following table summarizes the aggregate carrying amount and fair value of long-term debt, including current portion and excluding unamortized loss on refunded debt at December 31 (in thousands).

2013		2012	
Carrying Amount	Fair Value	Carrying Amount	Fair Value
$ 2,362,500	$ 2,436,199	$ 2,400,154	$ 2,875,955

The estimated fair value amounts were determined using rates that are currently available for issuance of debt with similar credit ratings and maturities. As market interest rates decline in relation to the issuer's outstanding debt, the fair value of outstanding debt financial instruments with fixed interest rates and maturities will tend to rise. Conversely, as market interest rates increase, the fair value of outstanding debt financial instruments will tend to decline. Fair value will normally approximate carrying amount as the debt financial instrument nears its maturity date. The use of different market assumptions may have an effect on the estimated fair value amount. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that bondholders could realize in a current market exchange.

5. BENEFIT PLANS FOR EMPLOYEES AND RETIREES

RETIREMENT PLAN

Plan Description - All full-time employees are covered by the Omaha Public Power District Retirement Plan (Retirement Plan) as they are not covered by Social Security. It is a single-employer, defined benefit plan that provides retirement and death benefits to Retirement Plan members and beneficiaries. The Retirement Plan was established and may be amended at the direction of the Board of Directors and is administered by OPPD. Actuarial valuations are completed as of January 1 of each year. As of January 1, 2013, 1,821 of the 4,527 total participants were receiving benefits. Generally, employees at the normal retirement age of 65 are entitled to annual pension benefits equal to 2.25% of their average compensation (as defined) times years of credited service (as defined) under the Traditional provision (as defined). Under the Cash Balance provision (as defined), members can receive the total vested value of their Cash Balance Account at separation from employment. Employees were allowed to make a one-time irrevocable election to have benefits determined based on the Cash Balance provision instead of the Traditional provision. There were 213 members with the Cash Balance provision as of December 31, 2013. Effective January 1, 2013, all new employees are only eligible for the Cash Balance provision.

Funded Status and Funding Progress - Employees contributed 6.2% of their covered payroll to the Retirement Plan for the years ended December 31, 2013 and 2012. OPPD is obligated to contribute the balance of the funds needed on an actuarially determined basis.

The Actuarial Accrued Liability (AAL) is the present value of retirement benefits adjusted for assumptions for future increases in compensation and service attributable to past accounting periods. The funded ratio for the AAL assumes future compensation and service increases. The annual

contributions to the Retirement Plan consist of the cost for the current period plus a portion of the Unfunded Accrued Liability.

The following table summarizes the AAL and other pension information based on the actuarial valuation as of January 1 (dollars in thousands).

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) (b)	Unfunded Accrued Liability (UAL) (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAL Percentage of Covered Payroll ((b-a)/c)
2013	$ 852,552	$ 1,184,997	$ 332,445	71.9%	$ 188,675	176.2%
2012	$ 805,763	$ 1,155,410	$ 349,647	69.7%	$ 192,169	181.9%
2011	$ 771,588	$ 1,094,909	$ 323,321	70.5%	$ 187,285	172.6%

The Present Value of Accrued Plan Benefits (PVAPB) is the present value of benefits based on compensation and service to the date of the actuarial valuation. This is the amount the Retirement Plan would owe participants if the Retirement Plan were frozen on the valuation date. The PVAPB was $1,027,635,000, and the Underfunded PVAPB was $175,083,000 as of January 1, 2013. The funded ratio was 83.0% as of January 1, 2013.

Annual Pension Cost and Actuarial Assumptions - The annual pension cost and annual required contribution (ARC) was $52,387,000 and $53,463,000 for the years ended December 31, 2013 and 2012, respectively. Accounting standards require recognition of a pension liability on the Statement of Net Position for the amount of any unfunded ARC. Since the entire ARC was funded, there was no net pension obligation as of December 31, 2013 and 2012. Retirement Plan contributions by employees for their covered annual payroll were $11,568,000 and $11,517,000 for the years ended December 31, 2013 and 2012, respectively.

The Entry Age Normal (Level Percent of Pay) cost method was used to determine contributions to the Retirement Plan. Under this actuarial method, an allocation to past service and future service is made by spreading the costs over an employee's career as a level percentage of pay. The actuarial value of Retirement Plan assets was determined using a method which smoothes the effect of short-term volatility in the market value of investments over approximately five years. Ad-hoc cost-of-living adjustments are provided to retirees and beneficiaries at the discretion of the Board of Directors and are amortized in the year for which the increase is authorized. Except for the liability associated with cost-of-living adjustments, the unfunded actuarial accrued liability was amortized on a level basis (closed group) over 15 years. The healthy mortality table used was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011. The disabled mortality table used was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Disabled Retiree Mortality Table for 2011.

The other actuarial assumptions for the valuations as of January 1, 2013, 2012 and 2011, were as follows:

- The investment return (discount rate) was 7.75%.
- The average rate of compensation increase was 5.2%.
- There were no ad-hoc cost-of-living adjustments.

Other employee benefit obligations are provided to allow certain current and former employees to retain the benefits to which they would have been entitled under the Retirement Plan, except for federally mandated limits and to provide supplemental pension benefits. The related pension expense, fund balance and employee benefit obligation were not material for the years ended December 31, 2013 and 2012.

DEFINED CONTRIBUTION RETIREMENT SAVINGS PLAN – 401(k)/457

OPPD sponsors a Defined Contribution Retirement Savings Plan – 401(k) (401k Plan) and a Defined Contribution Retirement Savings Plan – 457 (457 Plan). Both the 401k Plan and 457 Plan cover all full-time employees and allow contributions by employees that are partially matched by OPPD. The 401k Plan's and 457 Plan's assets and income are held in an external trust account in the employee's name. The matching share of contributions was $6,932,000 and $7,128,000 for the years ended December 31, 2013 and 2012, respectively. The employer maximum annual match on employee contributions was $4,000 per employee for the years ended December 31, 2013 and 2012.

POST EMPLOYMENT BENEFITS OTHER THAN PENSIONS

There are two separate plans for Other Post Employment Benefits (OPEB). OPEB Plan A provides post-employment health care and life insurance benefits to qualifying members. OPEB Plan B provides post-employment health care premium coverage for the Company's share to qualifying members who were hired after December 31, 2007.

OPEB Plan A

Plan Description – OPEB Plan A (Plan A) provides post employment health care benefits to retirees, surviving spouses, and employees on long-term disability and their dependents and life insurance benefits to retirees and employees on long term disability. Health care benefits are based on the coverage elected by Plan A members. OPPD's Medical Plan becomes a secondary plan when the members are retired and eligible for Medicare benefits. As of January 1, 2013, 1,666 of the 3,934 total members were receiving benefits.

Funded Status and Funding Progress – Plan A members are required to pay a monthly premium based on the elected coverage and the respective premium cost share. OPPD contributes the balance of the funds needed on an actuarially determined basis.

The Actuarial Accrued Liability (AAL) is the present value of benefits attributable to past accounting periods.

The following table summarizes AAL and other OPEB Plan A information based on the actuarial valuation as of January 1 (in thousands).

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) (b)	Unfunded Accrued Liability (UAL) (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAL Percentage of Covered Payroll ((b-a)/c)
2013	$ 88,527	$ 322,995	$ 234,468	27.4%	$ 188,675	124.3%
2012	$ 68,130	$ 380,426	$ 312,296	17.9%	$ 192,169	162.5%
2011	$ 51,274	$ 360,200	$ 308,926	14.2%	$ 187,285	164.9%

Annual OPEB Cost and Actuarial Assumptions – The annual OPEB cost and ARC for OPEB Plan A was $21,361,000 and $30,698,000 for the years ended December 31, 2013 and 2012, respectively. The decrease from the prior year was due to plan design changes. Accounting standards require recognition of an OPEB liability on the Statement of Net Position for the amount of any unfunded ARC. Since the entire ARC was funded, there was no net OPEB obligation as of December 31, 2013 and 2012. Contributions by Plan A members were $3,098,000 and $2,819,000 for the years ended December 31, 2013 and 2012, respectively.

The actuarial assumptions and methods used for the valuations on January 1, 2013, 2012 and 2011, were as follows:

- The pre-Medicare health care trend rates ranged from 8.0% initial to 5.0% ultimate.
- The post-Medicare health care trend rates ranged from 7.5% initial to 5.0% ultimate.
- The investment return (discount rate) used was 7.5%, which was based on OPPD's expected long-term return on assets used to finance the payment of plan benefits.
- The average rate of compensation increase used was 5.2%.
- The actuarial cost method used was the Projected Unit Credit.
- Amortization for the initial unfunded AAL and OPEB Plan changes was determined using a period of 30 years and the increasing method at a rate of 3.0% per year.
- Amortization for all changes (including gains/losses, assumption and plan provisions) after the initial year were determined using a closed period of 15 years and the level dollar method.
- The mortality table used for healthy participants was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011.

OPEB Plan B

Plan Description – OPEB Plan B (Plan B) provides post-employment health care premium coverage for the Company's share for retirees and surviving spouses and their dependents to qualifying members who were hired after December 31, 2007. Benefits are based on the coverage elected by the Plan B members and the balance in the member's hypothetical account, which is a bookkeeping account. The hypothetical accounts are credited with $10,000 upon commencement of full-time employment, $1,000 annually on the member's anniversary date and interest income at 5.0% annually. Plan B benefits are

for the payment of OPPD's share of the members' health care premiums. Plan benefits will continue until the member and eligible spouse cease to be covered under OPPD's Medical Plan, the member's hypothetical account is depleted or Plan B terminates, whichever occurs first. Benefits are forfeited for any member who fails to retire or who retires but does not immediately commence payments. As of January 1, 2013, only 1 of the 565 Plan B members was receiving benefits.

Funded Status and Funding Progress – Funds are contributed, as needed, on an actuarially determined basis. Members do not contribute to Plan B.

The following table summarizes AAL and other OPEB Plan B information based on the actuarial valuations as of January 1 (in thousands).

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (b)	Overfunded Accrued Liability (OAL) (a - b)	Funded Ratio (a/b)	Covered Payroll (c)	OAL Percentage of Covered Payroll ((a-b)/c)
2013	$ 3,633	$ 1,033	$ 2,600	351.7%	$ 41,942	6.2%
2012	$ 3,507	$ 756	$ 2,751	463.9%	$ 33,193	8.3%
2011	$ 3,281	$ 486	$ 2,795	675.1%	$ 23,888	11.7%

Annual OPEB Cost and Actuarial Assumptions – There was no ARC for OPEB Plan B for the years ended December 31, 2013 and 2012. The annual OPEB cost was $148,000 and $96,000 for the years ended December 31, 2013 and 2012, respectively. There was an OPEB net asset of $1,519,000 and $1,667,000 as of December 31, 2013 and 2012, respectively.

The actuarial assumptions and methods used for the valuations on January 1, 2013, 2012 and 2011 were as follows:

- The investment return (discount rate) used was 5.5%, which was based on OPPD's expected long-term return on assets used to finance the payment of plan benefits.
- The actuarial cost method used was Projected Unit Credit.
- Amortization for gains/losses was determined using a closed period of 15 years and the level dollar method.
- The mortality table for healthy participants was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011.

SELF-INSURANCE HEALTH PROGRAM

Employee health care and life insurance benefits are provided to substantially all full-time employees. There were 2,097 and 2,110 full-time employees with medical coverage as of December 31, 2013 and 2012, respectively. An Administrative Services Only (ASO) Health Insurance Program is used to account for the health insurance claims. With respect to the ASO program, reserves sufficient to satisfy

both statutory and OPPD-directed requirements have been established to provide risk protection (Note 3). Additionally, private insurance has been purchased to cover claims in excess of 125% of expected aggregate levels and $450,000 per member.

Health care expenses for full-time employees (reduced by premium payments from participants) were $22,894,000 and $23,107,000 for the years ended December 31, 2013 and 2012, respectively.

The total cost of life and long-term disability insurance for full-time employees was $791,000 and $1,015,000 for the years ended December 31, 2013 and 2012, respectively.

The balance of the Incurred But Not Presented Reserve was $2,374,000 and $2,310,000 as of December 31, 2013 and 2012, respectively.

Audited financial statements for the Retirement Plan, Defined Contribution Retirement Savings Plans and OPEB Plans may be reviewed by contacting the Pension Administrator at Corporate Headquarters.

6. ADDITIONS TO AND UTILIZATIONS OF RESERVES

The Debt Retirement Reserve was used to provide additional revenues and funding for capital expenditures and debt retirement in the amount of $17,000,000 for the years ended December 31, 2013 and 2012.

There were no net revenue adjustments from changes to the Rate Stabilization Reserve for the years ended December 31, 2013 and 2012.

7. DERIVATIVES

OPPD entered into natural gas futures contracts with the New York Mercantile Exchange (NYMEX) to hedge expected cash flows associated with purchases of natural gas for operations. As required by generally accepted accounting principles, the natural gas futures contracts were evaluated and determined to be effective hedges. Accordingly, the deferred cash flow hedges for the unrealized losses and the fair value of the commodity derivative instruments were reported on the Statement of Net Position.

The futures contracts were with NYMEX based on the notional amount of 80,000 and 280,000 Million Metric British Thermal Units (mmBtu) of natural gas with negative fair values and deferred cash outflows of $119,000 and $502,000 as of December 31, 2013 and 2012, respectively. The fair value and deferred cash outflows for these contracts were determined using published pricing benchmarks obtained through independent sources. All of these contracts will be settled based on the pricing point at Henry Hub on their respective expiration date. The accumulated decrease in fair value of hedging derivatives was reported in deferred outflows of resources.

The balance in the margin account of $172,000 was reported with the fair value of the derivative instruments. The net amount for commodity derivative instruments reported in other current assets was $53,000 and $416,000 as of December 31, 2013 and 2012, respectively (Note 2). There were realized

losses of $336,000 and $1,176,000 for the years ended December 31, 2013 and 2012, respectively. Realized gains or losses from effective hedges are included in fuel expense.

The following table summarizes information regarding the NYMEX natural gas contracts outstanding, along with the deferred cash outflows of the aggregate contracts by maturity dates, as of December 31, 2013 (dollars in thousands).

Effective Date	Maturity Date	Reference Rate	Notional Amount (mmBtu)	Fair Value/ Change
Various	June 2014	Pay Average $5.578/mmBtu	10,000	$ (15)
Various	July 2014	Pay Average $5.626/mmBtu	40,000	(59)
Various	August 2014	Pay Average $5.670/mmBtu	30,000	(45)
		Total	80,000	$ (119)

Basis Risk – Basis risk is the risk that arises when variable rates or prices of a hedging derivative instrument and a hedged item are based on different reference rates. Location basis risk is created by purchasing natural gas at the Northern Natural Gas "Demarcation" pricing point and entering into the futures contract at the Henry Hub pricing point. Critical terms risk exists because the hedging instrument is a monthly transaction and the purchase of physical natural gas is typically a daily transaction. These two differences create the greatest amount of variation between the hedging instruments and the price paid for physical purchases.

Rollover Risk – Rollover risk is the risk that a hedging derivative instrument associated with a hedgeable item does not extend to the maturity of that hedgeable item. Rollover risk exists because the purchase of natural gas for the generation of electricity is an ongoing process whereas the hedges are only for the summer load months.

8. OTHER – NET

The following table summarizes the composition of Other – Net for the years ended December 31 (in thousands).

	2013	2012
Interest subsidies from the federal government	$ 2,113	$ 2,281
Grants from FEMA	1,588	5,082
Health care subsidies from the federal government	811	617
Other	221	884
Total	$ 4,733	$ 8,864

9. LOSSES AND RECOVERIES

Due to record snowfall in the Rocky Mountains and high water levels in the Missouri River Reservoirs, the United States Army Corps of Engineers released record amounts of water from dams along the Missouri River in 2011. This release of water caused flooding in areas near the Missouri River and impacted the operation of FCS. The reactor was in cold shut-down starting in April 2011 due

to the start of a planned refueling outage. In June 2011, outage activities were suspended to protect FCS facilities from rising river levels. In September 2011, water levels had receded enough to allow outage activities to resume and inspections for any flood damage to begin.

The Missouri River flood (Flood Event) impacted all of the coal and nuclear generating units and some transmission and distribution structures. Estimated expenditures for the Flood Event were $840,000 and $11,493,000 for the years ended December 31, 2013 and 2012, respectively. These expenditures were partially offset by insurance recoveries and grants from the Federal Emergency Management Agency (FEMA). The balance of the FEMA receivable for the Flood Event was $11,579,000 and $19,941,000 as of December 31, 2013 and 2012, respectively.

Increased fuel costs and unexpected energy purchases were incurred due to the FCS extended outage, which resulted in FPPA under-recoveries for 2013 and 2012. Insurance recoveries of $36,643,000 were recognized in 2012 from an insurance policy for outages caused by accidental property damage at FCS. The insurance policy was acquired to mitigate the financial impact of qualifying outages, including additional fuel and purchased power expenses. The Board of Directors authorized the use of these insurance proceeds to reduce the FPPA regulatory asset, consistent with the objective of this policy. Insurance proceeds of $24,000,000 and $12,643,000 were received in January 2013 and October 2012, respectively.

Insurance recoveries for property damage to the North Omaha Station Unit 5 generator of $1,171,000 were recognized for the year ended December 31, 2013. Insurance recoveries for property damage from the breaker fire at FCS of $1,750,000 were recognized for the year ended December 31, 2012. The balance of receivables from insurance companies was $590,000 and $25,432,000 as of December 31, 2013 and 2012, respectively.

OPPD followed the provisions of GASB Codification Section 1400.196, *Insurance Recoveries,* which provides that insurance recoveries should be recognized only when realized or realizable (i.e., when the insurer has admitted or acknowledged coverage). Impairment losses should be reported net of the associated insurance recovery when the recovery and the loss occur in the same year; and, insurance recoveries reported in subsequent years should be reported as program revenue, nonoperating revenue, or extraordinary item, as appropriate.

The following table summarizes the adjustments for insurance recoveries and the impact on income and expenses for the years ended December 31 (in thousands).

	2013	**2012**
Increase in Other Electric Revenues	$ 9	$ 23,080
(Increase) Decrease in Operating Expenses	(494)	15,115
(Decrease) Increase in CIAC	(358)	2,108
Total	$ (843)	$ 40,303

10. NUCLEAR REGULATORY COMMISSION OVERSIGHT

The NRC placed FCS into a special category of their inspection manual, Chapter 0350, in December 2011. This Chapter is for nuclear plants that are in extended shutdowns with performance issues.

In August 2012, the Board of Directors authorized management to enter into a long-term operating service agreement with Exelon Generation Company, LLC, (Exelon) to provide operating and managerial support at FCS for 20 years. OPPD remains the owner and licensed operator of the station, while Exelon will have day-to-day operational authority at FCS, subject to oversight by and decision-making authority of OPPD for licensed activities. The Exelon Nuclear Management Model is being used to improve and sustain performance at FCS. Operations resumed in December 2013.

11. COMMITMENTS AND CONTINGENCIES

Commitments for the uncompleted portion of construction contracts were approximately $45,412,000 at December 31, 2013.

Power sales commitments which extend through 2027 were $100,743,000 as of December 31, 2013. Power purchase commitments which extend through 2020 were $94,994,000 as of December 31, 2013. These amounts do not include the Participation Power Agreements (PPAs) for OPPD's commitments for wind energy purchases or NC2.

The following table summarizes OPPD's PPAs for wind purchase agreements as of December 31, 2013.

	Total Capacity (in MW)	OPPD Share (in MW)	Commitment Through	Amount (In thousands)
Ainsworth *	59.4	10.0	2025	$ 26,619
Elkhorn Ridge *	80.0	25.0	2028	11,475
Flat Water **	60.0	60.0	2030	122
Petersburg **	40.5	40.5	2031	336
Prairie Breeze **	200.6	200.6	2038	360
	440.5	336.1		$ 38,912

The Ainsworth facility located near Ainsworth, Nebraska and the Elkhorn Ridge facility located near Bloomfield, Nebraska are owned by the Nebraska Public Power District. The Flat Water facility is located near Humboldt, Nebraska. The Petersburg facility is located near Petersburg, Nebraska. The Prairie Breeze facility is located near Elgin, Nebraska.

* *These PPAs are on a "take-or-pay" basis and the Company is obligated to make payments for purchased power even if the power is not available, delivered or taken by OPPD. For the Ainsworth agreement, OPPD is obligated, through a step-up provision, to pay a share of any deficit in funds resulting from the default.*

***These PPAs are on a "take-and-pay basis and require payments only when the power is made available to OPPD.*

There are 40-year PPAs with seven public power and municipal utilities (the Participants) for the sale of half of the 684.6-megawatt (MW) net capacity of NC2. The Participants have agreed to purchase their respective shares of the output on a "take-or-pay" basis even if the power is not available,

delivered to or taken by the Participants. The Participants are subject to a step-up provision, whereby in the event of a Participant default, the remaining Participants are obligated to pay a share of any deficit in funds resulting from the default. There is an NC2 Transmission Facilities Cost Agreement with the Participants that addresses the cost allocation, payment and cost recovery for delivery of their respective power.

OPPD has coal supply contracts which extend through 2017 with minimum future payments of $231,292,000 at December 31, 2013. The Company also has coal-transportation contracts which extend through 2020 with minimum future payments of $597,121,000 as of December 31, 2013. These contracts are subject to price adjustments.

Contracts for uranium concentrate and conversion services are in effect through 2016 with estimated future payments of $38,904,000 as of December 31, 2013. Contracts for the enrichment of nuclear fuel are in effect through 2026 with estimated future payments of $182,331,000 as of December 31, 2013. Additionally, OPPD has contracts through 2022 for the fabrication of nuclear fuel assemblies with estimated future payments of $47,227,000 as of December 31, 2013.

There is a 20 year operating agreement with Exelon for operational and managerial support services at FCS. The Company remains the owner and licensed operator. The Company may terminate the agreement at any time without cause during the term of the agreement upon 180 days' prior notice subject to a termination fee of $20,000,000 and payment of certain additional termination costs. Termination for cause and certain other termination events are not subject to payment of a termination fee.

In 2007, OPPD and the Metropolitan Community College (MCC) executed an Educational Services Agreement for $1,000,000 of educational services (as defined in the Agreement) over a ten-year period. If OPPD has not purchased the educational services by the end of the term, MCC shall have the right to extend the Agreement for an additional five years. As of December 31, 2013, OPPD's remaining commitment was $434,000.

Under the provisions of the Price-Anderson Act as of December 31, 2013, OPPD and all other licensed nuclear power plant operators could each be assessed for claims and legal costs in the event of a nuclear incident in amounts not to exceed a total of $127,318,000 per reactor per incident with a maximum of $18,963,000 per incident in any one calendar year. These amounts are subject to adjustment every five years in accordance with the Consumer Price Index.

OPPD is engaged in routine litigation incidental to the conduct of its business and, in the opinion of Management, based upon the advice of General Counsel, the aggregate amounts recoverable or payable, taking into account amounts provided in the financial statements, are not significant.

12. SUBSEQUENT EVENTS

A PPA with Geronimo Energy was signed on January 28, 2014. This agreement was to purchase 400 MW of wind energy from the Grande Prairie wind farm. The wind farm is scheduled to begin commercial operations in 2016. Energy purchases by OPPD are expected to commence in 2017, when transmission services are available.

Statistics (Unaudited)

	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
Total Utility Plant										
(at year end)										
(in thousands of dollars)	**5,288,168**	5,187,395	5,027,093	4,865,417	4,678,449	4,561,815	4,259,501	4,166,997	3,656,433	3,363,909
Total Indebtedness										
(at year end)										
(in thousands of dollars)	**2,267,277**	2,296,305	2,085,540	2,011,969	1,937,704	1,902,403	1,866,472	1,565,807	1,133,171	894,020
Operating Revenues										
(in thousands of dollars)										
Residential	**385,171**	362,105	337,053	335,294	292,887	271,935	267,042	249,174	237,798	211,913
Commercial	**306,719**	292,296	274,102	284,400	265,668	238,496	228,060	213,314	204,314	194,684
Industrial	**213,742**	197,225	186,417	164,621	139,865	109,827	100,239	94,109	90,344	90,987
Off-System Sales	**118,268**	123,191	159,732	184,374	158,354	127,676	110,399	96,500	120,030	109,523
FPPA Revenue	**15,169**	(3,237)	35,345	269	—	—	—	—	—	—
Unbilled Revenues	**4,490**	4,517	(4,239)	1,232	7,449	3,391	1,742	2,527	630	(1,134)
Provision for Debt Retirement	**17,000**	17,000	24,000	(13,000)	13,000	20,000	27,000	(15,000)	—	(55,000)
Other Electric Revenues	**29,654**	54,900	29,352	29,160	22,743	16,648	15,771	36,204	13,436	15,342
Total	**1,090,213**	1,047,997	1,041,762	986,350	899,966	787,973	750,253	676,828	666,552	566,315
Operations & Maintenance Expenses										
(in thousands of dollars)	**796,104**	770,073	789,516	720,957	653,993	561,396	508,524	461,101	447,270	401,778
Payments in Lieu of Taxes										
(in thousands of dollars)	**31,827**	30,094	28,217	27,851	24,810	22,426	21,398	20,241	19,693	18,591
Net Operating Revenues before Depreciation and Amortization										
(in thousands of dollars)	**262,282**	247,830	224,029	237,542	221,163	204,151	220,331	195,486	199,589	145,946
Net Income										
(in thousands of dollars)	**55,276**	54,829	54,440	40,047	46,557	79,186	89,489	84,290	82,171	24,844
Energy Sales										
(in megawatt-hours)										
Residential	**3,607,439**	3,595,316	3,602,973	3,644,400	3,361,672	3,486,858	3,546,116	3,374,053	3,356,196	3,054,576
Commercial	**3,561,707**	3,492,745	3,481,459	3,777,092	3,672,982	3,758,853	3,750,634	3,577,436	3,535,036	3,369,713
Industrial	**3,606,611**	3,670,346	3,698,719	3,427,710	3,039,396	2,877,282	2,759,087	2,664,743	2,644,634	2,630,038
Off-System Sales	**3,925,574**	3,671,978	4,631,175	5,552,645	5,534,803	3,003,888	2,858,004	2,486,483	2,502,433	3,646,043
Unbilled Sales	**26,221**	28,558	(85,917)	(24,109)	74,416	50,374	13,858	9,628	21,285	6,890
Total	**14,727,552**	14,458,943	15,328,409	16,377,738	15,683,269	13,177,255	12,927,699	12,112,343	12,059,584	12,707,260
Number of Customers										
(average per year)										
Residential	**311,921**	308,516	308,412	303,374	299,813	296,648	293,642	289,713	282,310	275,854
Commercial	**44,221**	43,589	43,564	43,225	43,134	42,867	42,214	41,488	40,665	39,834
Industrial	**193**	210	206	154	151	142	134	132	133	135
Off-System	**33**	35	41	38	34	32	35	37	39	45
Total	**356,368**	352,350	352,223	346,791	343,132	339,689	336,025	331,370	323,147	315,868
Cents Per kWh (average)										
Residential	**10.68**	10.12	9.37	9.22	8.77	7.82	7.51	7.40	7.07	6.95
Commercial	**8.61**	8.40	7.89	7.54	7.29	6.36	6.07	5.99	5.77	5.76
Industrial	**5.96**	5.38	5.05	4.83	4.62	3.82	3.64	3.55	3.46	3.40
Retail	**8.43**	7.94	7.42	7.26	6.96	6.13	5.93	5.81	5.58	5.48
Generating Capability										
(at year end)										
(in megawatts)	**3,237.0**	3,208.8	3,222.7	3,224.7	3,223.9	2,548.8	2,548.8	2,544.1	2,542.5	2,540.5
System Peak Load										
(in megawatts)	**2,339.4**	2,451.6	2,468.3	2,402.8	2,316.4	2,181.1	2,197.4	2,271.9	2,223.3	2,143.8
Net System Requirements										
(in megawatt-hours)										
Generated	**13,209,542**	12,855,389	13,807,712	15,870,513	15,263,983	12,477,032	12,274,660	11,341,827	11,180,808	12,235,044
Purchased and Net Interchanged	**(1,819,871)**	(1,529,643)	(2,576,167)	(4,428,059)	(4,627,627)	(1,864,214)	(1,738,833)	(1,268,780)	(1,148,903)	(2,716,242)
Net	**11,389,671**	11,325,746	11,231,545	11,442,454	10,636,356	10,612,818	10,535,827	10,073,047	10,031,905	9,518,802

Statements of Net Position
as of December 31, 2013 and 2012

ASSETS	2013	2012
	(thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$ **92,852**	$ 60,486
Electric system revenue fund	**29,962**	-
Electric system revenue bond fund	**73,961**	56,960
Electric system subordinated revenue bond fund	**6,440**	6,440
Electric system construction fund	**154,981**	324,191
NC2 separate electric system revenue fund	**13,852**	13,827
NC2 separate electric system revenue bond fund	**8,592**	8,555
NC2 separate electric system capital costs fund	**309**	3,371
Accounts receivable - net	**132,972**	150,599
Fossil fuels - at average cost	**28,910**	46,485
Materials and supplies - at average cost	**126,211**	109,899
Other (Note 2)	**31,840**	28,883
Total current assets	**700,882**	809,696
SPECIAL PURPOSE FUNDS - at fair value		
Electric system revenue bond fund - net of current	**55,681**	60,484
Segregated fund - debt retirement (Note 3)	-	14,000
Segregated fund - rate stabilization (Note 3)	**32,000**	24,612
Segregated fund - other (Note 3)	**33,586**	34,819
Decommissioning funds (Note 3)	**346,118**	349,724
Total special purpose funds	**467,385**	483,639
UTILITY PLANT - at cost		
Electric plant	**5,186,399**	5,086,630
Less accumulated depreciation and amortization	**1,929,027**	1,844,664
Electric plant - net	**3,257,372**	3,241,966
Nuclear fuel - at amortized cost	**101,769**	100,765
Total utility plant - net	**3,359,141**	3,342,731
OTHER LONG-TERM ASSETS (Note 2)	**290,241**	200,247
TOTAL ASSETS	**4,817,649**	4,836,313
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on refunded debt	**29,191**	33,000
Accumulated change in fair value of hedging derivatives (Note 7)	**119**	502
Total deferred outflows of resources	**29,310**	33,502
TOTAL ASSETS AND DEFERRED OUTFLOWS	**$ 4,846,959**	$ 4,869,815

See notes to financial statements

LIABILITIES	2013	2012
	(thousands)	
CURRENT LIABILITIES		
Electric system revenue bonds (Note 4)	**$ 30,545**	$ 26,125
Electric revenue notes - commercial paper series (Note 4)	**-**	150,000
NC2 separate electric system revenue bonds (Note 4)	**2,970**	2,865
Subordinated obligation (Note 4)	**442**	406
Accounts payable	**69,720**	91,758
Accrued payments in lieu of taxes	**30,769**	29,034
Accrued interest	**42,931**	39,366
Accrued payroll	**32,753**	31,830
NC2 participant deposits	**7,428**	8,926
Other (Note 2)	**4,847**	5,637
Total current liabilities	**222,405**	385,947
LIABILITIES PAYABLE FROM SEGREGATED FUNDS (Note 2)	**30,387**	31,684
LONG-TERM DEBT (Note 4)		
Electric system revenue bonds - net of current	**1,471,830**	1,502,375
Electric system subordinated revenue bonds	**346,270**	346,270
Electric revenue notes - commercial paper series	**150,000**	-
Minibonds	**28,495**	28,127
NC2 separate electric system revenue bonds - net of current	**236,725**	239,695
Subordinated obligation - net of current	**-**	442
Total long-term debt	**2,233,320**	2,116,909
Unamortized discounts and premiums	**95,223**	103,849
Total long-term debt - net	**2,328,543**	2,220,758
OTHER LIABILITIES		
Decommissioning costs	**346,118**	349,724
Other (Note 2)	**12,918**	13,390
Total other liabilities	**359,036**	363,114
COMMITMENTS AND CONTINGENCIES (Note 11)		
TOTAL LIABILITIES	**2,940,371**	3,001,503
DEFERRED INFLOWS OF RESOURCES		
Rate stabilization reserve (Note 6)	**32,000**	32,000
Debt retirement reserve (Note 6)	**-**	17,000
Uncollectible accounts reserve - off-system	**5,000**	5,000
Total deferred inflows of resources	**37,000**	54,000
NET POSITION		
Net investment in capital assets	**1,254,740**	1,380,992
Restricted	**39,589**	25,295
Unrestricted	**575,259**	408,025
Total net position	**1,869,588**	1,814,312
TOTAL LIABILITIES, DEFERRED INFLOWS AND NET POSITION	**$ 4,846,959**	$ 4,869,815

See notes to financial statements

Statements of Revenues, Expenses and Changes in Net Position for the Years Ended December 31, 2013 and 2012

	2013	2012
	(thousands)	
OPERATING REVENUES		
Retail sales	$ 942,291	$ 869,906
Off-system sales	118,268	123,191
Other electric revenues	29,654	54,900
Total operating revenues	1,090,213	1,047,997
OPERATING EXPENSES		
Operations and maintenance		
Fuel	215,533	236,557
Purchased power	84,139	73,966
Production	265,124	228,559
Transmission	24,010	21,996
Distribution	44,180	37,073
Customer accounts	15,165	13,949
Customer service and information	15,126	16,360
Administrative and general	132,827	141,613
Total operations and maintenance	796,104	770,073
Depreciation and amortization	130,407	128,794
Payments in lieu of taxes	31,827	30,094
Total operating expenses	958,338	928,961
OPERATING INCOME	131,875	119,036
OTHER INCOME (EXPENSES)		
Contributions in aid of construction	18,570	13,066
Reduction of plant costs recovered through contributions in aid of construction	(18,570)	(13,066)
Decommissioning funds - investment income	3,606	12,833
Decommissioning funds - reinvestment	(3,606)	(12,833)
Investment income (loss)	(339)	2,041
Allowances for funds used during construction	13,334	14,234
Products and services - net	3,228	3,279
Other - net (Note 8)	4,733	8,864
Total other income - net	20,956	28,418
INTEREST EXPENSE	97,555	92,625
NET INCOME	55,276	54,829
NET POSITION, BEGINNING OF YEAR	1,814,312	1,759,483
NET POSITION, END OF YEAR	$1,869,588	$ 1,814,312

See notes to financial statements

Statements of Cash Flows
for the Years Ended December 31, 2013 and 2012

	2013	2012
	(thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash received from retail customers	$ 939,617	$ 897,540
Cash received from off-system counterparties	108,453	107,733
Cash received from insurance companies	24,000	17,656
Cash paid to operations and maintenance suppliers	(620,474)	(626,679)
Cash paid to off-system counterparties	(82,808)	(59,940)
Cash paid to employees	(169,988)	(156,361)
Cash paid for in lieu of taxes and other taxes	(30,092)	(28,216)
Net cash provided from operating activities	168,708	151,733
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Proceeds from long-term borrowings	-	560,881
Principal reduction of debt	(29,539)	(289,085)
Interest paid on debt	(97,285)	(106,411)
Acquisition and construction of capital assets	(166,052)	(178,785)
Proceeds from NC2 participants	3,560	2,848
Contributions in aid of construction and other reimbursements	19,953	13,293
Acquisition of nuclear fuel	(4,800)	(10,813)
Net cash used for capital and related financing activities	(274,163)	(8,072)
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of investments	(531,951)	(860,586)
Maturities and sales of investments	666,793	743,528
Purchases of investments for decommissioning funds	(204,516)	(291,237)
Maturities and sales of investments in decommissioning funds	204,516	291,237
Investment income	2,979	3,222
Net cash provided from (used for) investing activities	137,821	(113,836)
CHANGE IN CASH AND CASH EQUIVALENTS	32,366	29,825
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	60,486	30,661
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 92,852	$ 60,486
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED FROM OPERATING ACTIVITIES		
Operating income	$ 131,875	$ 119,036
Adjustments to reconcile operating income to net cash provided from operating activities		
Depreciation and amortization	130,407	128,794
Amortization of nuclear fuel	564	-
Changes in assets and liabilities		
Accounts receivable	3,191	(25,849)
Fossil fuels	17,575	5,198
Materials and supplies	(16,312)	(8,289)
Regulatory asset for FPPA	(15,169)	3,237
Accounts payable	(5,436)	3,432
Accrued payments in lieu of taxes	1,735	1,878
Accrued payroll	923	2,493
Debt retirement reserve	(17,000)	(17,000)
Regulatory asset for FCS recovery costs	(67,735)	(70,627)
Other	4,090	9,430
Net cash provided from operating activities	$ 168,708	$ 151,733
NONCASH CAPITAL ACTIVITIES		
Utility plant additions from outstanding liabilities	$ 13,983	$ 30,590

See notes to financial statements

Notes to Financial Statements
as of and for the Years Ended December 31, 2013 and 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Business – The Omaha Public Power District (OPPD or Company), a political subdivision of the state of Nebraska, is a public utility engaged in the generation, transmission and distribution of electric power and energy and other related activities. The Board of Directors is authorized to establish rates. OPPD is generally not liable for federal and state income or ad valorem taxes on property; however, payments in lieu of taxes are made to various local governments.

Basis of Accounting – The financial statements are presented in accordance with generally accepted accounting principles (GAAP) for proprietary funds of governmental entities. Accounting records are maintained generally in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and all applicable pronouncements of the Governmental Accounting Standards Board (GASB).

OPPD applies the accounting policies established in the GASB Codification Section Re10, *Regulated Operations.* This guidance permits an entity with cost-based rates to include costs in a period other than the period in which the costs would be charged to expense by an unregulated entity if it is probable that these costs will be recovered through rates charged to customers. This guidance also permits an entity to defer revenues by recognizing liabilities to cover future expenditures. The guidance applies to OPPD because the rates of the Company's regulated operations are established and approved by the governing board.

If, as a result of changes in regulation or competition, the ability to recover these assets and to satisfy these liabilities would not be assured, OPPD would be required to write off or write down such regulatory assets and liabilities, unless some form of transition cost recovery continues through established rates. In addition, any impairment to the carrying costs of deregulated plant and inventory assets would be determined. There were no write-downs of regulatory assets for the years ended December 31, 2013 and 2012.

Classification of Revenues and Expenses – Revenues and expenses related to providing energy services in connection with the Company's principal ongoing operations are classified as operating. All other revenues and expenses are classified as non-operating and reported as other income (expenses) on the Statements of Revenue, Expenses and Changes in Net Position.

Revenue Recognition – Electric operating revenues are recognized as earned. Meters are read and bills are rendered on a cycle basis. Revenues earned after meters are read are estimated and accrued as unbilled revenues at the end of each accounting period.

Cash and Cash Equivalents – The operating fund account is called the Electric System Revenue Fund (Note 3). Highly liquid investments for the Electric System Revenue Fund with an original maturity of three months or less are considered to be cash equivalents. Cash and cash equivalents in the Special Purpose Funds are reported as investments.

Accounts Receivable – Accounts Receivable includes outstanding amounts from customers and an estimate for unbilled revenues. An estimate is made for the Reserve for Uncollectible Accounts for retail customers based on an analysis of Accounts Receivable and historical write-offs net of recoveries. Additional amounts may be included based on the credit risks of significant parties. Accounts Receivable includes $45,905,000 and $41,415,000 in unbilled revenues as of December 31, 2013 and 2012, respectively. Accounts Receivable was reported net of the Reserve for Uncollectible Accounts of $1,000,000 and $1,020,000 as of December 31, 2013 and 2012, respectively.

Utility Plant – Utility plant is stated at cost, which includes property additions, replacements of units of property and betterments. Maintenance and replacement of minor items are charged to operating expenses. Costs of depreciable units of electric plant retirements are eliminated from electric plant accounts by charges, less salvage plus removal expenses, to the accumulated depreciation account. Electric plant includes both tangible and intangible assets. Intangible assets include costs related to regulatory licenses, software licenses and other rights to use property. Electric plant includes construction work in progress of $404,042,000 and $394,415,000 as of December 31, 2013 and 2012, respectively.

The following table summarizes electric plant balances as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Retirements	2013
Electric plant	$ 5,086,630	$ 163,887	$ (64,118)	$ 5,186,399
Less accumulated depreciation & amortization	1,844,664	146,910	(62,547)	1,929,027
Electric plant - net	$ 3,241,966	$ 16,977	$ (1,571)	$ 3,257,372

Allowances for funds used during construction (AFUDC), approximates OPPD's current weighted average cost of debt. AFUDC was capitalized as a component of the cost of utility plant. These allowances for both construction work in progress and nuclear fuel were computed at 3.8% and 4.3% for the years ended December 31, 2013 and 2012, respectively.

The carrying amounts of long-lived assets for impairment are periodically reviewed. An asset is considered impaired when the magnitude of the decline in service utility is significant and not part of the normal life cycle of the capital asset. There were no write-downs for impairments for the years ended December 31, 2013 and 2012.

Contributions in Aid of Construction (CIAC) – Payments are received from customers for construction costs primarily relating to the expansion of the electric system. FERC guidelines are followed in recording CIAC. These guidelines direct the reduction of utility plant assets by the amount of contributions received toward the construction of utility plant. CIAC is recorded as other income and offset by an expense in the same amount representing the recovery of plant costs. This allows for compliance with GASB Codification Section N50, *Nonexchange Transactions*, while continuing to follow FERC guidelines. CIAC from participants for the capital costs of Nebraska City Station Unit 2 (NC2) was $5,091,000 and $4,725,000 for the years ended December 31, 2013 and 2012, respectively.

Depreciation and Amortization – Depreciation for assets is computed on the straight-line basis at rates based on the estimated useful lives of the various classes of property. Depreciation expense for depreciable property averaged approximately 2.8% and 2.9% for the years ended December 31, 2013 and 2012, respectively.

Amortization of nuclear fuel is based on the cost thereof, and is prorated by fuel assembly in accordance with the thermal energy that each assembly produces. Intangible assets are amortized over their expected useful life. Amortization of intangible assets, included with depreciation and amortization expense in these financial statements, was $3,508,000 and $4,669,000 for the years ended December 31, 2013 and 2012, respectively.

NC2 was placed in commercial operation in 2009. Half of the unit's output is sold under 40-year Participation Power Agreements (PPAs). Certain participants funded their share of construction costs with NC2 Separate Electric System Revenue Bonds. These participants are billed for the debt service related to these bonds. The amounts recovered for debt service for the electric plant construction and other costs are included in off-system sales revenues. The revenues related to principal repayment will equal related depreciation and other deferred NC2 expenses over the 40-year term of the PPAs. A regulatory asset was established to equate expenses and the amount included in off-system sales revenues for principal repayment in order to maintain revenue neutrality in the interim years. This regulatory asset will increase annually until 2030 when principal repayments begin exceeding depreciation and other deferred expenses. After 2030, the regulatory asset will be reduced annually by recognizing deferred depreciation and other deferred expenses until its elimination in 2049, which is the end of the initial term of the PPAs.

In 2004, the Board of Directors approved a change in the depreciation estimate for Fort Calhoun production plant assets to 2043. This estimate is ten years beyond the term of Fort Calhoun Station's (FCS) current operating license. A regulatory asset was established for the difference in depreciation expense resulting from the use of the estimated economic life of the asset versus the license term. The reduction in depreciation expense will be recorded each year as a regulatory asset in deferred charges until 2033. The regulatory asset will be reduced through the recognition of depreciation expense over the assets' remaining economic life in the years 2034 through 2043.

Nuclear Fuel Disposal Costs – Permanent disposal of spent nuclear fuel is the responsibility of the federal government under an agreement entered into with the Department of Energy (DOE). Under the agreement, there is a fee of one mill per kilowatt-hour on net electricity generated and sold from FCS. The spent nuclear fuel disposal costs are included in nuclear fuel amortization and are collected from customers as part of fuel costs. There were nuclear fuel disposal costs of $91,000 and $0 for the years ended December 31, 2013 and 2012, respectively.

The agreement required the federal government to begin accepting high-level nuclear waste by January 1998; however, the DOE does not have a storage facility. In May 1998, the United States Court of Appeals confirmed the DOE's statutory obligation to accept spent fuel by 1998, but rejected the request that a move-fuel order be issued. In March 2001, OPPD, along with a number of other utilities, filed suit against the DOE in the United States Court of Federal Claims alleging breach of contract.

In 2006, the DOE agreed to reimburse OPPD for allowable costs for managing and storing spent nuclear fuel and high-level waste incurred due to the DOE's delay in accepting waste. Applications are submitted periodically to the DOE for reimbursement of costs incurred for the storage of high-level nuclear waste and any reimbursements are included in CIAC.

Nuclear Decommissioning – The Board of Directors has approved the collection of nuclear decommissioning costs based on an independent engineering study of the costs to decommission FCS. Based on cost estimates, inflation rates and fund earnings projections, no funding has been necessary since 2001. Decommissioning funds are reported at fair value. The decommissioning cost liability is adjusted for investment income and changes in fair value, resulting in no impact on net income. Investment income was $6,477,000 and $7,534,000 for the years ended December 31, 2013 and 2012, respectively. The fair value of the decommissioning funds decreased $10,083,000 and increased $5,299,000 during 2013 and 2012, respectively. The present value of the total decommissioning cost estimate for FCS was $851,912,000 and $733,314,000 as of June 30, 2013 and 2012, respectively.

Regulatory Assets and Liabilities – Rates for regulated operations are established and approved by the Board of Directors. The provisions of GASB Codification Section Re10, *Regulated Operations*, are applied. This guidance provides that regulatory assets are rights to additional revenues or deferred expenses, which are expected to be recovered through customer rates over some future period. Regulatory liabilities are reductions in earnings (or costs recovered) to cover future expenditures.

A Major Planned Production Outage (Outage), as defined by OPPD, is an outage with incremental operations and maintenance expenses of $5,000,000 or more. These Outages are periodically completed to maintain and enhance the performance and efficiency of station operations, which benefits the station over the next operating cycle of production. In October 2013, the Board of Directors authorized regulatory accounting treatment for qualifying Outage costs to allow the use of the defer-and-amortize method. Eligible outage costs will be deferred as a regulatory asset and amortized to expense over the subsequent operating cycle. The first outage that will qualify for this regulatory accounting treatment is at FCS. Pre-outage costs are expected to be deferred commencing in 2015.

A Fuel and Purchased Power Adjustment (FPPA) was implemented in the retail rate structure in 2010. The Board of Directors authorized the use of regulatory accounting to maintain revenue neutrality by matching retail revenues attributed to fuel and purchased power costs with the actual costs incurred. Additional fuel and purchased power expenses were incurred as a result of the extended outage at FCS. This resulted in FPPA under-recoveries of $35,124,000 and $45,375,000 for the years ended December 31, 2013 and 2012, respectively. The FPPA regulatory assets were reduced for customer collections of $19,955,000 and $11,969,000 in 2013 and 2012, respectively. FCS outage insurance recoveries of $36,643,000 further reduced this regulatory asset in 2012.

The Regulatory Asset for FPPA, included in Other Current Assets, was $23,020,000 and $19,955,000 as of December 31, 2013 and 2012, respectively (Note 2). The Regulatory Asset for FPPA, included in Other Long-Term Assets, was $24,526,000 and $12,422,000 as of December 31, 2013 and 2012, respectively (Note 2). This regulatory asset represented the rights to additional revenues based on incurred expenses due to under-recoveries of fuel and purchased power costs.

Additional regulatory assets included in Other Long-Term Assets consist of deferred financing costs and other deferred expenses for FCS and NC2. In 2004, the Board of Directors approved a change in the depreciation estimate for FCS production assets to 2043. This estimate is ten years beyond the term of the current operating license. NC2 was placed in commercial operation in 2009. As previously noted, certain NC2 expenses were deferred to maintain revenue neutrality from transactions with participants who funded their share of construction costs with NC2 Separate Electric System Revenue Bonds.

The Board of Directors authorized the use of regulatory accounting for debt issuance costs in 2012 because of new accounting standards which would have required these costs to be expensed in the period incurred. These costs are amortized over the life of the associated bond issues consistent with the rate methodology. The Board of Directors also authorized the use of regulatory accounting in 2012 for significant, unplanned operations and maintenance costs at FCS incurred to address concerns from the Nuclear Regulatory Commission (NRC) and enhance operations. These costs will be amortized over a ten-year period which commenced in December 2013 with FCS's return to service.

The following table summarizes the balances of the Regulatory Assets as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Reductions	2013
Regulatory asset for FCS - Recovery Costs	$ 70,627	$ 68,811	$ (1,076)	$ 138,362
Regulatory asset for FCS - depreciation	54,705	6,485	-	61,190
Regulatory asset for NC2	37,067	4,190	-	41,257
Regulatory asset for FPPA	32,377	35,124	(19,955)	47,546
Regulatory asset for financing costs	17,266	-	(979)	16,287
	$ 212,042	$ 114,610	$ (22,010)	$ 304,642

Regulatory liabilities, which are deferred inflows of resources, consist of reserves for debt retirement, rate stabilization and uncollectible accounts from off-system sales. The Debt Retirement Reserve was established for the retirement of outstanding debt and to help maintain debt service coverage ratios at appropriate levels (Note 6). The Rate Stabilization Reserve was established to help maintain stability in OPPD's long-term rate structure (Note 6). The Uncollectible Accounts Reserve - Off-System was established to recognize a loss contingency for uncollectible accounts from off-system sales customers based on the greater of $5,000,000 or an estimate (as defined) considering the previous year's accounts receivable balances for off-system sales customers.

The following table summarizes the balances of the Regulatory Liabilities as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Reductions	2013
Rate stabilization reserve	$ 32,000	$ -	$ -	$ 32,000
Debt retirement reserve	17,000	-	(17,000)	-
Uncollectible accounts reserve - off-system	5,000	-	-	5,000
	$ 54,000	$ -	$ (17,000)	$ 37,000

Natural Gas Inventories and Contracts – Natural gas inventories are maintained for the Cass County Station. The weighted average cost of natural gas consumed is used to expense natural gas from inventories. OPPD is exposed to market price fluctuations on its purchases of natural gas. The Company may enter into futures contracts and purchase options to manage the risk of volatility in the market price of gas on anticipated purchase transactions (Note 7).

Net Position – Net Position is reported in three separate components on the Statement of Net Position. Net Investment in Capital Assets is the net position share attributable to net utility plant assets reduced by outstanding related debt. Restricted is the share of net position that has usage restraints imposed by law or by debt covenants, such as certain revenue bond funds and segregated funds, net of related liabilities. Unrestricted is the share of net position that is neither restricted nor invested in capital assets.

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.

Recent Accounting Pronouncements – In June 2012, GASB issued Statement No. 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27.* The objective of this statement is to improve accounting and financial reporting for pensions. This statement requires governments to more comprehensively and comparably measure the annual costs of pension benefits. This statement also enhances accountability and transparency through revised and new note disclosures and required supplementary information. This statement is effective for reporting periods beginning after June 15, 2014. This statement will be implemented in 2015. The implementation of this statement will result in the recognition of a net pension liability for the statement of net position, a change in the pension expense calculation for the statement of revenues, expenses and changes in net position and additional note disclosures and required supplementary information.

In November 2013, GASB issued Statement No. 71, *Pension Transition for Contributions Made Subsequent to the Measurement Date – an amendment of GASB Statement No. 68.* The objective of this statement is to clarify accounting and financial reporting for pensions. This statement requires governments to recognize a beginning deferred outflow of resources for pension contributions made subsequent to the measurement date of the beginning net pension liability calculated under GASB Statement No. 68. This statement is effective for reporting periods beginning after June 15, 2014 and will be applied simultaneously with GASB Statement No. 68 in 2015.

2. ASSETS AND LIABILITIES DETAIL BALANCES

Other Current Assets

The composition as of December 31 was as follows (in thousands):

	2013	2012
Regulatory asset for FPPA	$ 23,020	$ 19,955
Prepayments	5,475	4,948
Sulfur dioxide allowance inventory	2,841	2,799
Interest receivable	375	642
Commodity derivative instruments (Note 7)	53	416
Other	76	123
Total	$ 31,840	$ 28,883

Other Long-Term Assets

The composition as of December 31 was as follows (in thousands):

	2013	2012
Regulatory asset for FCS - Recovery Costs	$ 138,362	$ 70,627
Regulatory asset for FCS - depreciation	61,190	54,705
Regulatory asset for NC2	41,257	37,067
Regulatory asset for FPPA	24,526	12,422
Regulatory asset for financing costs	16,287	17,266
Deposit with SPP	2,000	-
Sulfur dioxide allowance inventory	-	1,625
Other	6,619	6,535
Total	$ 290,241	$ 200,247

Other Current Liabilities

The composition as of December 31 was as follows (in thousands):

	2013	2012
Unearned revenues	$ 3,310	$ 2,441
Deposits	1,022	804
Payroll taxes and other employee liabilities	475	1,963
Other	40	429
Total	$ 4,847	$ 5,637

Liabilities Payable from Segregated Funds

The composition as of December 31 was as follows (in thousands):

	2013	2012
Customer deposits	$ 22,673	$ 24,293
Customer advances for construction	3,342	3,413
Incurred but not presented reserve	2,374	2,310
Other	1,998	1,668
Total	$ 30,387	$ 31,684

Other Liabilities

The composition as of December 31 was as follows (in thousands):

	2013	2012
Unearned revenues	$ 8,757	$ 9,219
Capital purchase agreement	1,951	2,175
Workers' compensation reserve	1,558	1,344
Public liability reserve	190	199
Other	462	453
Total	$ 12,918	$ 13,390

3. FUNDS AND INVESTMENTS

Funds of OPPD were as follows:

Electric System Revenue Fund and NC2 Separate Electric System Revenue Fund – These funds are to be used for operating activities for their respective electric system. Cash and cash equivalents in the Electric System Revenue Fund are shown separately from investments on the Statement of Net Position.

Electric System Revenue Bond Fund, Electric System Subordinated Revenue Bond Fund and NC2 Separate Electric System Revenue Bond Fund – These funds are to be used for the retirement of their respective revenue bonds and the payment of the related interest and reserves as required. Investments with maturity dates within the next year are designated as current.

Electric System Construction Fund and NC2 Separate Electric System Capital Costs Fund – These funds are to be used for capital improvements, additions and betterments to and extensions of their respective electric system.

Segregated Fund – Debt Retirement – This fund is to be used for the retirement of outstanding debt and to assist in maintaining debt service coverage ratios at appropriate levels. Since there is no funding requirement for the Debt Retirement Reserve, this fund also may be used to provide additional liquidity for operations as necessary. The balance of the Debt Retirement Fund was $0 and $14,000,000 as of December 31, 2013 and 2012, respectively.

Segregated Fund – Rate Stabilization – This fund is to be used to help stabilize rates through the transfer of funds to operations as necessary. Since there is no funding requirement for the Rate

Stabilization Reserve, this fund also may be used to provide additional liquidity for operations as necessary. This fund was used to help finance the higher fuel costs and unexpected energy purchases in 2011. Proceeds from the FCS outage insurance and customer collections for prior year FPPA under-recoveries were used to replenish this fund in 2013 and 2012. The balance of the Rate Stabilization Fund was $32,000,000 and $24,612,000 as of December 31, 2013 and 2012, respectively.

Segregated Fund – Other – This fund represents assets held for payment of customer deposits, refundable advances, certain other liabilities and funds set aside for terminal removal costs for NC2 and OPPD's self-insured health insurance plans (Note 5).

The following table summarizes the balances of the segregated funds as of December 31 (in thousands).

	2013	2012
Segregated Fund - self-insurance	$ 5,135	$ 5,106
Segregated Fund - other	28,451	29,713
Total	$ 33,586	$ 34,819

Decommissioning Funds – These funds are for the costs to decommission FCS when its operating license expires. The Decommissioning Funds are held by an outside trustee in compliance with the decommissioning funding plans approved by the Board of Directors. The 1990 Plan was established in accordance with NRC regulations for the purpose of discharging the obligation to decommission FCS. The 1992 Plan was established to retain funds in excess of NRC minimum funding requirements based on an independent engineering study which indicated that decommissioning costs would exceed the NRC minimum requirements.

The following table summarizes the balances of the decommissioning funds as of December 31 (in thousands).

	2013	2012
Decommissioning Trust - 1990 Plan	$ 264,758	$ 267,278
Decommissioning Trust - 1992 Plan	81,360	82,446
Total	$ 346,118	$ 349,724

Fair Value of Investments – These values were determined based on quotes received from trustees' market valuation services.

The following table summarizes OPPD's investments as of December 31 (in thousands). The weighted average maturity was based on the face value for investments.

	2013		2012	
		Weighted Average		Weighted Average
Investment Type	**Fair Value**	**Maturity (Years)**	**Fair Value**	**Maturity (Years)**
Commercial paper	$ 52,425	0.5	$ -	-
Money market	1,160	-	25,825	-
Mutual funds	183,960	-	186,842	-
U.S. agencies	352,127	1.5	538,450	1.4
U.S. treasuries	65,414	3.3	126,902	2.2
Corporate bonds	23,645	2.5	18,548	3.3
World bank security notes	76,314	0.1	-	-
Total	$755,045		$ 896,567	
Portfolio weighted average maturity		1.2		1.2

Interest Rate Risk – The investment in relatively short-term securities reduces interest rate risk, as evidenced by its portfolio weighted average maturity of 1.2 years as of December 31, 2013 and 2012. In addition, OPPD is a buy-and-hold investor, which minimizes interest rate risk.

Credit Risk – The investment policy is to comply with bond covenants and state statutes for governmental entities, which limit investments to investment-grade fixed income obligations. OPPD was in full compliance with bond covenants and state statutes as of December 31, 2013 and 2012.

Custodial Credit Risk – Bank deposits were entirely insured or collateralized with securities held by OPPD or by its agent in OPPD's name at December 31, 2013 and 2012. All investment securities are delivered under contractual trust agreements.

4. DEBT

The proceeds of debt issued are utilized primarily to finance the construction program.

The following table summarizes the debt balances as of December 31, 2012, activity for 2013 and balances as of December 31, 2013 (in thousands).

	2012	Additions	Retirements	2013
Electric system revenue bonds	$ 1,528,500	$ -	$ (26,125)	$ 1,502,375
Electric system subordinated revenue bonds	346,270	-	-	346,270
Electric revenue notes - commercial paper series	150,000	-	-	150,000
Minibonds	28,127	537	(169)	28,495
NC2 separate electric system revenue bonds	242,560	-	(2,865)	239,695
Subordinated obligation	848	-	(406)	442
Total	$ 2,296,305	$ 537	$ (29,565)	$ 2,267,277

Lien Structure – In the event of a default, subject to the terms and conditions of debt covenants, OPPD is required to satisfy all Electric System Revenue Bond obligations before paying second-tier bonds and notes which are Electric System Subordinated Revenue Bonds, Electric Revenue Notes – Commercial Paper Series and Minibonds. OPPD will pay the Subordinated Obligation after second-tier debt.

Electric System Revenue Bonds – These bonds are payable from and secured by a pledge of and lien upon the revenues of the Electric System, subject to the prior payment therefrom of the operations and maintenance expenses of the Electric System. The Electric System Revenue Bonds are Senior Bonds.

Moody's Investors Service and Standard & Poor's Rating Services rated the Electric System Revenue Bonds as Aa2 and AA in 2013 and Aa1 and AA in 2012.

The following table summarizes outstanding Electric System Revenue Bonds as of December 31, 2013, (in thousands).

Issue	Maturity Dates	Type	Interest Rates	Amount
1993 Series C	2014	Term	5.5%	$ 9,385
2005 Series B	2017 - 2022	Serial	5.0%	17,740
2007 Series A	2018 - 2027	Serial	4.0% - 5.0%	108,705
2007 Series A	2029 - 2043	Term	4.75% - 5.0%	136,295
2008 Series A	2018 - 2028	Serial	4.6% - 5.5%	34,710
2008 Series A	2029 - 2039	Term	5.5%	70,290
2009 Series A	2023 - 2029	Serial	4.0% - 4.75%	25,700
2009 Series A	2030 - 2039	Term	5.0%	59,300
2010 Series A	2022 - 2041	Term	5.431%	120,000
2011 Series A	2014 - 2024	Serial	3.0% - 5.0%	143,375
2011 Series B	2023 - 2029	Serial	3.25% - 5.0%	34,570
2011 Series B	2031 - 2042	Term	4.0% - 5.0%	103,360
2011 Series C	2014 - 2030	Serial	2.5% - 5.0%	139,575
2012 Series A	2023 - 2034	Serial	4.0% - 5.0%	139,480
2012 Series A	2035 - 2042	Term	5.0%	133,175
2012 Series B	2017 - 2034	Serial	3.0% - 5.0%	141,295
2012 Series B	2038 - 2046	Term	3.75% - 5.0%	85,420
Total				$ 1,502,375

The following table summarizes outstanding Electric System Revenue Bonds as of December 31, 2012 (in thousands).

Issue	Maturity Dates	Type	Interest Rates	Amount
1993 Series C	2013 - 2014	Term	5.5%	$ 27,620
2003 Series A	2013	Serial	3.8%	7,000
2005 Series B	2017 - 2022	Serial	5.0%	17,740
2007 Series A	2018 - 2027	Serial	4.0% - 5.0%	108,705
2007 Series A	2029 - 2043	Term	4.75% - 5.0%	136,295
2008 Series A	2018 - 2028	Serial	4.6% - 5.5%	34,710
2008 Series A	2029 - 2039	Term	5.5%	70,290
2009 Series A	2023 - 2029	Serial	4.0% - 4.75%	25,700
2009 Series A	2030 - 2039	Term	5.0%	59,300
2010 Series A	2022 - 2041	Term	5.431%	120,000
2011 Series A	2014 - 2024	Serial	3.0% - 5.0%	143,375
2011 Series B	2023 - 2029	Serial	3.25% - 5.0%	34,570
2011 Series B	2031 - 2042	Term	4.0% - 5.0%	103,360
2011 Series C	2013 - 2030	Serial	2.0% - 5.0%	140,465
2012 Series A	2023 - 2034	Serial	4.0% - 5.0%	139,480
2012 Series A	2035 - 2042	Term	5.0%	133,175
2012 Series B	2017 - 2034	Serial	3.0% - 5.0%	141,295
2012 Series B	2038 - 2046	Term	3.75% - 5.0%	85,420
Total				$ 1,528,500

On February 1, 2013, a principal payment of $16,740,000 was made for the Electric System Revenue Bonds. On August 1, 2013, a principal payment of $9,385,000 was made for the call of the 1993 Series C term bonds due February 1, 2014. Term bonds are subject to call every six months.

On February 1, 2012, a principal payment of $29,620,000 was made for the Electric System Revenue Bonds. On August 1, 2012, a principal payment of $8,850,000 was made for the call of the 1993 Series C term bonds due February 1, 2013. Term bonds are subject to call every six months. On November 1, 2012, a principal payment of $13,990,000 was made for the call of the 2002 Series B Electric System Revenue Bonds due on February 1, 2013. On October 10, 2012, OPPD issued 2012 Series A Electric System Revenue Bonds and Series B Electric System Revenue Bonds. The 2012 Series B Electric System Revenue Bonds were used for the refunding of portions of the 2005 Series B and 2006 Series A Bonds. The refunding reduced total debt service payments over the life of the bonds by $39,963,000 and resulted in an economic gain (difference between the present values of the old and new debt service payments) of $25,357,000.

Electric System Revenue Bonds, from the following series, with outstanding principal amounts of $325,780,000 as of December 31, 2013, were legally defeased: 1986 Series A, 1992 Series B, 1993 Series B, 2005 Series B and 2006 Series A. Electric System Revenue Bonds, from the following series, with outstanding principal amounts of $426,125,000 as of December 31, 2012, were legally defeased: 1986 Series A, 1992 Series B, 1993 Series B, 2003 Series A, 2005 Series B and 2006 Series

A. Defeased bonds are funded by government securities in irrevocable escrow accounts. Accordingly, the bonds and the related government securities escrow accounts are not included in the Statement of Net Position.

OPPD's bond indenture, amended effective March 4, 2009, provides for certain restrictions, the most significant of which are:

- Additional bonds may not be issued unless estimated net receipts (as defined) for each future year equal or exceed 1.4 times the debt service on all Electric System Revenue Bonds outstanding, including the additional bonds being issued or to be issued in the case of a power plant (as defined) being financed in increments.

- The Electric System is required to be maintained by the Company in good condition.

The following table summarizes Electric System Revenue Bond payments (in thousands).

	Principal	Interest
2014	$ 30,545	$ 70,994
2015	40,465	69,448
2016	43,065	67,573
2017	45,900	65,636
2018	47,815	63,656
2019 - 2023	221,415	286,224
2024 - 2028	228,470	233,860
2029 - 2033	274,910	172,945
2034 - 2038	273,620	109,117
2039 - 2043	239,870	34,139
2044 - 2046	56,300	3,533
Total	$ 1,502,375	$ 1,177,125

The average interest rate for Electric System Revenue Bonds was 4.8% for the years ended December 31, 2013 and 2012.

Electric System Subordinated Revenue Bonds – These bonds are payable from and secured by a pledge of revenues of the Electric System, subject to the prior payment of the operations and maintenance expenses of the Electric System and the prior payment of the Electric System Revenue Bonds. The payment of the principal and interest on these bonds is insured by a municipal bond insurance policy.

The Electric System Subordinated Revenue Bonds include Periodically Issued Bonds (PIBs). Certain issues of the PIBs may be redeemed prior to maturity upon the death of the holder subject to certain conditions as outlined in the offering document.

The following table summarizes Electric System Subordinated Revenue Bonds (PIBs) payments (in thousands).

	Principal	Interest
2014	$ -	$ 6,540
2015	-	6,540
2016	-	6,540
2017	-	6,540
2018	-	6,541
2019-2023	-	32,701
2024-2028	-	32,701
2029-2033	-	32,702
2034-2038	74,230	24,451
2039-2042	72,040	8,207
Total	$ 146,270	$ 163,463

The following table summarizes Electric System Subordinated Revenue Bond payments for the 2007 Series AA (in thousands).

	Principal	Interest
2014	$ -	$ 8,901
2015	-	8,902
2016	-	8,902
2017	-	8,902
2018	1,000	8,882
2019-2023	8,000	43,763
2024-2028	42,000	38,994
2029-2033	67,000	27,171
2034-2038	82,000	8,955
Total	$ 200,000	$ 163,372

The average interest rate for the Electric System Subordinated Revenue Bonds (PIBs and the 2007 Series AA) was 4.5% for the years ended December 31, 2013 and 2012.

Electric Revenue Notes - Commercial Paper Series – The outstanding balance of Commercial Paper was $150,000,000 as of December 31, 2013 and 2012. The average borrowing rates were 0.1% and 0.2% for the years ended December 31, 2013 and 2012, respectively. A Credit Agreement with Bank of America, N.A., includes a covenant to retain drawing capacity at least equal to the issued and outstanding amount of Commercial Paper Notes.

Minibonds – Minibonds consist of current interest-bearing and capital appreciation minibonds. The minibonds may be redeemed prior to their maturity dates at the request of a holder, subject to certain conditions as outlined in the Minibond Official Statement. There were no Minibond maturities in 2013 other than redemptions for the annual put option. The average interest rates were 5.05% for the years ended December 31, 2013 and 2012. The principal and interest on these bonds is insured by a municipal bond insurance policy.

The following table summarizes outstanding minibond balances at December 31 (in thousands).

Principal	**2013**	**2012**
2001 Minibonds, due 2021 (5.05%)	$ 23,460	$ 23,604
Accreted interest on capital appreciation minibonds	5,035	4,523
Total	$ 28,495	$ 28,127

Subordinated Obligation – The subordinated obligation is payable in annual installments of $482,000, which includes interest at 9.0%, through 2014.

Credit Agreements – OPPD has a Credit Agreement with the Bank of America, N.A., for $250,000,000 which will expire on October 1, 2015. The Credit Agreement includes a covenant to retain drawing capacity at least equal to the issued and outstanding amount of Commercial Paper Notes. The Company is in compliance with the Credit Agreement covenants. There were no amounts outstanding under this Credit Agreement as of December 31, 2013 and 2012.

NC2 Separate Electric System Revenue Bonds – Participation Power Agreements were executed with seven public power and municipal utilities for half of the output of NC2. The participants' rights to receive, and obligations to pay costs related to, half of the output is the "Separate System."

The following table summarizes NC2 Separate Electric System Revenue Bond payments (in thousands).

	Principal	**Interest**
2014	$ 2,970	$ 11,498
2015	3,080	11,381
2016	3,200	11,258
2017	3,330	11,128
2018	3,460	10,989
2019-2023	19,635	52,549
2024-2028	24,455	47,584
2029-2033	30,860	41,013
2034-2038	39,090	32,554
2039-2043	44,415	21,945
2044-2048	54,950	9,685
2049	10,250	256
Total	$ 239,695	$ 261,840

The payment of principal and interest on the 2005 Series A and 2006 Series A Bonds is insured by municipal bond insurance policies. The average interest rate for NC2 Separate Electric System Revenue Bonds was 4.8% for the years ended December 31, 2013 and 2012.

Fair Value Disclosure – The following table summarizes the aggregate carrying amount and fair value of long-term debt, including current portion and excluding unamortized loss on refunded debt at December 31 (in thousands).

2013		2012	
Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
$ 2,362,500	$ 2,436,199	$ 2,400,154	$ 2,875,955

The estimated fair value amounts were determined using rates that are currently available for issuance of debt with similar credit ratings and maturities. As market interest rates decline in relation to the issuer's outstanding debt, the fair value of outstanding debt financial instruments with fixed interest rates and maturities will tend to rise. Conversely, as market interest rates increase, the fair value of outstanding debt financial instruments will tend to decline. Fair value will normally approximate carrying amount as the debt financial instrument nears its maturity date. The use of different market assumptions may have an effect on the estimated fair value amount. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that bondholders could realize in a current market exchange.

5. BENEFIT PLANS FOR EMPLOYEES AND RETIREES

RETIREMENT PLAN

Plan Description - All full-time employees are covered by the Omaha Public Power District Retirement Plan (Retirement Plan) as they are not covered by Social Security. It is a single-employer, defined benefit plan that provides retirement and death benefits to Retirement Plan members and beneficiaries. The Retirement Plan was established and may be amended at the direction of the Board of Directors and is administered by OPPD. Actuarial valuations are completed as of January 1 of each year. As of January 1, 2013, 1,821 of the 4,527 total participants were receiving benefits. Generally, employees at the normal retirement age of 65 are entitled to annual pension benefits equal to 2.25% of their average compensation (as defined) times years of credited service (as defined) under the Traditional provision (as defined). Under the Cash Balance provision (as defined), members can receive the total vested value of their Cash Balance Account at separation from employment. Employees were allowed to make a one-time irrevocable election to have benefits determined based on the Cash Balance provision instead of the Traditional provision. There were 213 members with the Cash Balance provision as of December 31, 2013. Effective January 1, 2013, all new employees are only eligible for the Cash Balance provision.

Funded Status and Funding Progress - Employees contributed 6.2% of their covered payroll to the Retirement Plan for the years ended December 31, 2013 and 2012. OPPD is obligated to contribute the balance of the funds needed on an actuarially determined basis.

The Actuarial Accrued Liability (AAL) is the present value of retirement benefits adjusted for assumptions for future increases in compensation and service attributable to past accounting periods. The funded ratio for the AAL assumes future compensation and service increases. The annual

contributions to the Retirement Plan consist of the cost for the current period plus a portion of the Unfunded Accrued Liability.

The following table summarizes the AAL and other pension information based on the actuarial valuation as of January 1 (dollars in thousands).

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) (b)	Unfunded Accrued Liability (UAL) (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAL Percentage of Covered Payroll ((b-a)/c)
2013	$ 852,552	$ 1,184,997	$ 332,445	71.9%	$ 188,675	176.2%
2012	$ 805,763	$ 1,155,410	$ 349,647	69.7%	$ 192,169	181.9%
2011	$ 771,588	$ 1,094,909	$ 323,321	70.5%	$ 187,285	172.6%

The Present Value of Accrued Plan Benefits (PVAPB) is the present value of benefits based on compensation and service to the date of the actuarial valuation. This is the amount the Retirement Plan would owe participants if the Retirement Plan were frozen on the valuation date. The PVAPB was $1,027,635,000, and the Underfunded PVAPB was $175,083,000 as of January 1, 2013. The funded ratio was 83.0% as of January 1, 2013.

Annual Pension Cost and Actuarial Assumptions - The annual pension cost and annual required contribution (ARC) was $52,387,000 and $53,463,000 for the years ended December 31, 2013 and 2012, respectively. Accounting standards require recognition of a pension liability on the Statement of Net Position for the amount of any unfunded ARC. Since the entire ARC was funded, there was no net pension obligation as of December 31, 2013 and 2012. Retirement Plan contributions by employees for their covered annual payroll were $11,568,000 and $11,517,000 for the years ended December 31, 2013 and 2012, respectively.

The Entry Age Normal (Level Percent of Pay) cost method was used to determine contributions to the Retirement Plan. Under this actuarial method, an allocation to past service and future service is made by spreading the costs over an employee's career as a level percentage of pay. The actuarial value of Retirement Plan assets was determined using a method which smoothes the effect of short-term volatility in the market value of investments over approximately five years. Ad-hoc cost-of-living adjustments are provided to retirees and beneficiaries at the discretion of the Board of Directors and are amortized in the year for which the increase is authorized. Except for the liability associated with cost-of-living adjustments, the unfunded actuarial accrued liability was amortized on a level basis (closed group) over 15 years. The healthy mortality table used was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011. The disabled mortality table used was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Disabled Retiree Mortality Table for 2011.

The other actuarial assumptions for the valuations as of January 1, 2013, 2012 and 2011, were as follows:

- The investment return (discount rate) was 7.75%.
- The average rate of compensation increase was 5.2%.
- There were no ad-hoc cost-of-living adjustments.

Other employee benefit obligations are provided to allow certain current and former employees to retain the benefits to which they would have been entitled under the Retirement Plan, except for federally mandated limits and to provide supplemental pension benefits. The related pension expense, fund balance and employee benefit obligation were not material for the years ended December 31, 2013 and 2012.

DEFINED CONTRIBUTION RETIREMENT SAVINGS PLAN – 401(k)/457

OPPD sponsors a Defined Contribution Retirement Savings Plan – 401(k) (401k Plan) and a Defined Contribution Retirement Savings Plan – 457 (457 Plan). Both the 401k Plan and 457 Plan cover all full-time employees and allow contributions by employees that are partially matched by OPPD. The 401k Plan's and 457 Plan's assets and income are held in an external trust account in the employee's name. The matching share of contributions was $6,932,000 and $7,128,000 for the years ended December 31, 2013 and 2012, respectively. The employer maximum annual match on employee contributions was $4,000 per employee for the years ended December 31, 2013 and 2012.

POST EMPLOYMENT BENEFITS OTHER THAN PENSIONS

There are two separate plans for Other Post Employment Benefits (OPEB). OPEB Plan A provides post-employment health care and life insurance benefits to qualifying members. OPEB Plan B provides post-employment health care premium coverage for the Company's share to qualifying members who were hired after December 31, 2007.

OPEB Plan A

Plan Description – OPEB Plan A (Plan A) provides post employment health care benefits to retirees, surviving spouses, and employees on long-term disability and their dependents and life insurance benefits to retirees and employees on long term disability. Health care benefits are based on the coverage elected by Plan A members. OPPD's Medical Plan becomes a secondary plan when the members are retired and eligible for Medicare benefits. As of January 1, 2013, 1,666 of the 3,934 total members were receiving benefits.

Funded Status and Funding Progress – Plan A members are required to pay a monthly premium based on the elected coverage and the respective premium cost share. OPPD contributes the balance of the funds needed on an actuarially determined basis.

The Actuarial Accrued Liability (AAL) is the present value of benefits attributable to past accounting periods.

The following table summarizes AAL and other OPEB Plan A information based on the actuarial valuation as of January 1 (in thousands).

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) (b)	Unfunded Accrued Liability (UAL) (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAL Percentage of Covered Payroll ((b-a)/c)
2013	$ 88,527	$ 322,995	$ 234,468	27.4%	$ 188,675	124.3%
2012	$ 68,130	$ 380,426	$ 312,296	17.9%	$ 192,169	162.5%
2011	$ 51,274	$ 360,200	$ 308,926	14.2%	$ 187,285	164.9%

Annual OPEB Cost and Actuarial Assumptions – The annual OPEB cost and ARC for OPEB Plan A was $21,361,000 and $30,698,000 for the years ended December 31, 2013 and 2012, respectively. The decrease from the prior year was due to plan design changes. Accounting standards require recognition of an OPEB liability on the Statement of Net Position for the amount of any unfunded ARC. Since the entire ARC was funded, there was no net OPEB obligation as of December 31, 2013 and 2012. Contributions by Plan A members were $3,098,000 and $2,819,000 for the years ended December 31, 2013 and 2012, respectively.

The actuarial assumptions and methods used for the valuations on January 1, 2013, 2012 and 2011, were as follows:

- The pre-Medicare health care trend rates ranged from 8.0% initial to 5.0% ultimate.
- The post-Medicare health care trend rates ranged from 7.5% initial to 5.0% ultimate.
- The investment return (discount rate) used was 7.5%, which was based on OPPD's expected long-term return on assets used to finance the payment of plan benefits.
- The average rate of compensation increase used was 5.2%.
- The actuarial cost method used was the Projected Unit Credit.
- Amortization for the initial unfunded AAL and OPEB Plan changes was determined using a period of 30 years and the increasing method at a rate of 3.0% per year.
- Amortization for all changes (including gains/losses, assumption and plan provisions) after the initial year were determined using a closed period of 15 years and the level dollar method.
- The mortality table used for healthy participants was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011.

OPEB Plan B

Plan Description – OPEB Plan B (Plan B) provides post-employment health care premium coverage for the Company's share for retirees and surviving spouses and their dependents to qualifying members who were hired after December 31, 2007. Benefits are based on the coverage elected by the Plan B members and the balance in the member's hypothetical account, which is a bookkeeping account. The hypothetical accounts are credited with $10,000 upon commencement of full-time employment, $1,000 annually on the member's anniversary date and interest income at 5.0% annually. Plan B benefits are

for the payment of OPPD's share of the members' health care premiums. Plan benefits will continue until the member and eligible spouse cease to be covered under OPPD's Medical Plan, the member's hypothetical account is depleted or Plan B terminates, whichever occurs first. Benefits are forfeited for any member who fails to retire or who retires but does not immediately commence payments. As of January 1, 2013, only 1 of the 565 Plan B members was receiving benefits.

Funded Status and Funding Progress – Funds are contributed, as needed, on an actuarially determined basis. Members do not contribute to Plan B.

The following table summarizes AAL and other OPEB Plan B information based on the actuarial valuations as of January 1 (in thousands).

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (b)	Overfunded Accrued Liability (OAL) (a - b)	Funded Ratio (a/b)	Covered Payroll (c)	OAL Percentage of Covered Payroll ((a-b)/c)
2013	$ 3,633	$ 1,033	$ 2,600	351.7%	$ 41,942	6.2%
2012	$ 3,507	$ 756	$ 2,751	463.9%	$ 33,193	8.3%
2011	$ 3,281	$ 486	$ 2,795	675.1%	$ 23,888	11.7%

Annual OPEB Cost and Actuarial Assumptions – There was no ARC for OPEB Plan B for the years ended December 31, 2013 and 2012. The annual OPEB cost was $148,000 and $96,000 for the years ended December 31, 2013 and 2012, respectively. There was an OPEB net asset of $1,519,000 and $1,667,000 as of December 31, 2013 and 2012, respectively.

The actuarial assumptions and methods used for the valuations on January 1, 2013, 2012 and 2011 were as follows:

- The investment return (discount rate) used was 5.5%, which was based on OPPD's expected long-term return on assets used to finance the payment of plan benefits.
- The actuarial cost method used was Projected Unit Credit.
- Amortization for gains/losses was determined using a closed period of 15 years and the level dollar method.
- The mortality table for healthy participants was the Static Mortality Table for Annuitants and Non-Annuitants for 2013 and 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011.

SELF-INSURANCE HEALTH PROGRAM

Employee health care and life insurance benefits are provided to substantially all full-time employees. There were 2,097 and 2,110 full-time employees with medical coverage as of December 31, 2013 and 2012, respectively. An Administrative Services Only (ASO) Health Insurance Program is used to account for the health insurance claims. With respect to the ASO program, reserves sufficient to satisfy

both statutory and OPPD-directed requirements have been established to provide risk protection (Note 3). Additionally, private insurance has been purchased to cover claims in excess of 125% of expected aggregate levels and $450,000 per member.

Health care expenses for full-time employees (reduced by premium payments from participants) were $22,894,000 and $23,107,000 for the years ended December 31, 2013 and 2012, respectively.

The total cost of life and long-term disability insurance for full-time employees was $791,000 and $1,015,000 for the years ended December 31, 2013 and 2012, respectively.

The balance of the Incurred But Not Presented Reserve was $2,374,000 and $2,310,000 as of December 31, 2013 and 2012, respectively.

Audited financial statements for the Retirement Plan, Defined Contribution Retirement Savings Plans and OPEB Plans may be reviewed by contacting the Pension Administrator at Corporate Headquarters.

6. ADDITIONS TO AND UTILIZATIONS OF RESERVES

The Debt Retirement Reserve was used to provide additional revenues and funding for capital expenditures and debt retirement in the amount of $17,000,000 for the years ended December 31, 2013 and 2012.

There were no net revenue adjustments from changes to the Rate Stabilization Reserve for the years ended December 31, 2013 and 2012.

7. DERIVATIVES

OPPD entered into natural gas futures contracts with the New York Mercantile Exchange (NYMEX) to hedge expected cash flows associated with purchases of natural gas for operations. As required by generally accepted accounting principles, the natural gas futures contracts were evaluated and determined to be effective hedges. Accordingly, the deferred cash flow hedges for the unrealized losses and the fair value of the commodity derivative instruments were reported on the Statement of Net Position.

The futures contracts were with NYMEX based on the notional amount of 80,000 and 280,000 Million Metric British Thermal Units (mmBtu) of natural gas with negative fair values and deferred cash outflows of $119,000 and $502,000 as of December 31, 2013 and 2012, respectively. The fair value and deferred cash outflows for these contracts were determined using published pricing benchmarks obtained through independent sources. All of these contracts will be settled based on the pricing point at Henry Hub on their respective expiration date. The accumulated decrease in fair value of hedging derivatives was reported in deferred outflows of resources.

The balance in the margin account of $172,000 was reported with the fair value of the derivative instruments. The net amount for commodity derivative instruments reported in other current assets was $53,000 and $416,000 as of December 31, 2013 and 2012, respectively (Note 2). There were realized

losses of $336,000 and $1,176,000 for the years ended December 31, 2013 and 2012, respectively. Realized gains or losses from effective hedges are included in fuel expense.

The following table summarizes information regarding the NYMEX natural gas contracts outstanding, along with the deferred cash outflows of the aggregate contracts by maturity dates, as of December 31, 2013 (dollars in thousands).

Effective Date	Maturity Date	Reference Rate	Notional Amount (mmBtu)	Fair Value/ Change
Various	June 2014	Pay Average $5.578/mmBtu	10,000	$ (15)
Various	July 2014	Pay Average $5.626/mmBtu	40,000	(59)
Various	August 2014	Pay Average $5.670/mmBtu	30,000	(45)
		Total	80,000	$ (119)

Basis Risk – Basis risk is the risk that arises when variable rates or prices of a hedging derivative instrument and a hedged item are based on different reference rates. Location basis risk is created by purchasing natural gas at the Northern Natural Gas "Demarcation" pricing point and entering into the futures contract at the Henry Hub pricing point. Critical terms risk exists because the hedging instrument is a monthly transaction and the purchase of physical natural gas is typically a daily transaction. These two differences create the greatest amount of variation between the hedging instruments and the price paid for physical purchases.

Rollover Risk – Rollover risk is the risk that a hedging derivative instrument associated with a hedgeable item does not extend to the maturity of that hedgeable item. Rollover risk exists because the purchase of natural gas for the generation of electricity is an ongoing process whereas the hedges are only for the summer load months.

8. OTHER – NET

The following table summarizes the composition of Other – Net for the years ended December 31 (in thousands).

	2013	2012
Interest subsidies from the federal government	$ 2,113	$ 2,281
Grants from FEMA	1,588	5,082
Health care subsidies from the federal government	811	617
Other	221	884
Total	$ 4,733	$ 8,864

9. LOSSES AND RECOVERIES

Due to record snowfall in the Rocky Mountains and high water levels in the Missouri River Reservoirs, the United States Army Corps of Engineers released record amounts of water from dams along the Missouri River in 2011. This release of water caused flooding in areas near the Missouri River and impacted the operation of FCS. The reactor was in cold shut-down starting in April 2011 due

to the start of a planned refueling outage. In June 2011, outage activities were suspended to protect FCS facilities from rising river levels. In September 2011, water levels had receded enough to allow outage activities to resume and inspections for any flood damage to begin.

The Missouri River flood (Flood Event) impacted all of the coal and nuclear generating units and some transmission and distribution structures. Estimated expenditures for the Flood Event were $840,000 and $11,493,000 for the years ended December 31, 2013 and 2012, respectively. These expenditures were partially offset by insurance recoveries and grants from the Federal Emergency Management Agency (FEMA). The balance of the FEMA receivable for the Flood Event was $11,579,000 and $19,941,000 as of December 31, 2013 and 2012, respectively.

Increased fuel costs and unexpected energy purchases were incurred due to the FCS extended outage, which resulted in FPPA under-recoveries for 2013 and 2012. Insurance recoveries of $36,643,000 were recognized in 2012 from an insurance policy for outages caused by accidental property damage at FCS. The insurance policy was acquired to mitigate the financial impact of qualifying outages, including additional fuel and purchased power expenses. The Board of Directors authorized the use of these insurance proceeds to reduce the FPPA regulatory asset, consistent with the objective of this policy. Insurance proceeds of $24,000,000 and $12,643,000 were received in January 2013 and October 2012, respectively.

Insurance recoveries for property damage to the North Omaha Station Unit 5 generator of $1,171,000 were recognized for the year ended December 31, 2013. Insurance recoveries for property damage from the breaker fire at FCS of $1,750,000 were recognized for the year ended December 31, 2012. The balance of receivables from insurance companies was $590,000 and $25,432,000 as of December 31, 2013 and 2012, respectively.

OPPD followed the provisions of GASB Codification Section 1400.196, *Insurance Recoveries,* which provides that insurance recoveries should be recognized only when realized or realizable (i.e., when the insurer has admitted or acknowledged coverage). Impairment losses should be reported net of the associated insurance recovery when the recovery and the loss occur in the same year; and, insurance recoveries reported in subsequent years should be reported as program revenue, nonoperating revenue, or extraordinary item, as appropriate.

The following table summarizes the adjustments for insurance recoveries and the impact on income and expenses for the years ended December 31 (in thousands).

	2013	**2012**
Increase in Other Electric Revenues	$ 9	$ 23,080
(Increase) Decrease in Operating Expenses	(494)	15,115
(Decrease) Increase in CIAC	(358)	2,108
Total	$ (843)	$ 40,303

10. NUCLEAR REGULATORY COMMISSION OVERSIGHT

The NRC placed FCS into a special category of their inspection manual, Chapter 0350, in December 2011. This Chapter is for nuclear plants that are in extended shutdowns with performance issues.

In August 2012, the Board of Directors authorized management to enter into a long-term operating service agreement with Exelon Generation Company, LLC, (Exelon) to provide operating and managerial support at FCS for 20 years. OPPD remains the owner and licensed operator of the station, while Exelon will have day-to-day operational authority at FCS, subject to oversight by and decision-making authority of OPPD for licensed activities. The Exelon Nuclear Management Model is being used to improve and sustain performance at FCS. Operations resumed in December 2013.

11. COMMITMENTS AND CONTINGENCIES

Commitments for the uncompleted portion of construction contracts were approximately $45,412,000 at December 31, 2013.

Power sales commitments which extend through 2027 were $100,743,000 as of December 31, 2013. Power purchase commitments which extend through 2020 were $94,994,000 as of December 31, 2013. These amounts do not include the Participation Power Agreements (PPAs) for OPPD's commitments for wind energy purchases or NC2.

The following table summarizes OPPD's PPAs for wind purchase agreements as of December 31, 2013.

	Total Capacity (in MW)	OPPD Share (in MW)	Commitment Through	Amount (In thousands)
Ainsworth *	59.4	10.0	2025	$ 26,619
Elkhorn Ridge *	80.0	25.0	2028	11,475
Flat Water **	60.0	60.0	2030	122
Petersburg **	40.5	40.5	2031	336
Prairie Breeze **	200.6	200.6	2038	360
	440.5	336.1		$ 38,912

The Ainsworth facility located near Ainsworth, Nebraska and the Elkhorn Ridge facility located near Bloomfield, Nebraska are owned by the Nebraska Public Power District. The Flat Water facility is located near Humboldt, Nebraska. The Petersburg facility is located near Petersburg, Nebraska. The Prairie Breeze facility is located near Elgin, Nebraska.

* *These PPAs are on a "take-or-pay" basis and the Company is obligated to make payments for purchased power even if the power is not available, delivered or taken by OPPD. For the Ainsworth agreement, OPPD is obligated, through a step-up provision, to pay a share of any deficit in funds resulting from the default.*

** *These PPAs are on a "take-and-pay basis and require payments only when the power is made available to OPPD.*

There are 40-year PPAs with seven public power and municipal utilities (the Participants) for the sale of half of the 684.6-megawatt (MW) net capacity of NC2. The Participants have agreed to purchase their respective shares of the output on a "take-or-pay" basis even if the power is not available,

delivered to or taken by the Participants. The Participants are subject to a step-up provision, whereby in the event of a Participant default, the remaining Participants are obligated to pay a share of any deficit in funds resulting from the default. There is an NC2 Transmission Facilities Cost Agreement with the Participants that addresses the cost allocation, payment and cost recovery for delivery of their respective power.

OPPD has coal supply contracts which extend through 2017 with minimum future payments of $231,292,000 at December 31, 2013. The Company also has coal-transportation contracts which extend through 2020 with minimum future payments of $597,121,000 as of December 31, 2013. These contracts are subject to price adjustments.

Contracts for uranium concentrate and conversion services are in effect through 2016 with estimated future payments of $38,904,000 as of December 31, 2013. Contracts for the enrichment of nuclear fuel are in effect through 2026 with estimated future payments of $182,331,000 as of December 31, 2013. Additionally, OPPD has contracts through 2022 for the fabrication of nuclear fuel assemblies with estimated future payments of $47,227,000 as of December 31, 2013.

There is a 20 year operating agreement with Exelon for operational and managerial support services at FCS. The Company remains the owner and licensed operator. The Company may terminate the agreement at any time without cause during the term of the agreement upon 180 days' prior notice subject to a termination fee of $20,000,000 and payment of certain additional termination costs. Termination for cause and certain other termination events are not subject to payment of a termination fee.

In 2007, OPPD and the Metropolitan Community College (MCC) executed an Educational Services Agreement for $1,000,000 of educational services (as defined in the Agreement) over a ten-year period. If OPPD has not purchased the educational services by the end of the term, MCC shall have the right to extend the Agreement for an additional five years. As of December 31, 2013, OPPD's remaining commitment was $434,000.

Under the provisions of the Price-Anderson Act as of December 31, 2013, OPPD and all other licensed nuclear power plant operators could each be assessed for claims and legal costs in the event of a nuclear incident in amounts not to exceed a total of $127,318,000 per reactor per incident with a maximum of $18,963,000 per incident in any one calendar year. These amounts are subject to adjustment every five years in accordance with the Consumer Price Index.

OPPD is engaged in routine litigation incidental to the conduct of its business and, in the opinion of Management, based upon the advice of General Counsel, the aggregate amounts recoverable or payable, taking into account amounts provided in the financial statements, are not significant.

12. SUBSEQUENT EVENTS

A PPA with Geronimo Energy was signed on January 28, 2014. This agreement was to purchase 400 MW of wind energy from the Grande Prairie wind farm. The wind farm is scheduled to begin commercial operations in 2016. Energy purchases by OPPD are expected to commence in 2017, when transmission services are available.

Statistics (Unaudited)

	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
Total Utility Plant										
(at year end)										
(in thousands of dollars)	**5,288,168**	5,187,395	5,027,093	4,865,417	4,678,449	4,561,815	4,259,501	4,166,997	3,656,433	3,363,909
Total Indebtedness										
(at year end)										
(in thousands of dollars)	**2,267,277**	2,296,305	2,085,540	2,011,969	1,937,704	1,902,403	1,866,472	1,565,807	1,133,171	894,020
Operating Revenues										
(in thousands of dollars)										
Residential	**385,171**	362,105	337,053	335,294	292,887	271,935	267,042	249,174	237,798	211,913
Commercial	**306,719**	292,296	274,102	284,400	265,668	238,496	228,060	213,314	204,314	194,684
Industrial	**213,742**	197,225	186,417	164,621	139,865	109,827	100,239	94,109	90,344	90,987
Off-System Sales	**118,268**	123,191	159,732	184,374	158,354	127,676	110,399	96,500	120,030	109,523
FPPA Revenue	**15,169**	(3,237)	35,345	269	—	—	—	—	—	—
Unbilled Revenues	**4,490**	4,517	(4,239)	1,232	7,449	3,391	1,742	2,527	630	(1,134)
Provision for Debt Retirement	**17,000**	17,000	24,000	(13,000)	13,000	20,000	27,000	(15,000)	—	(55,000)
Other Electric Revenues	**29,654**	54,900	29,352	29,160	22,743	16,648	15,771	36,204	13,436	15,342
Total	**1,090,213**	1,047,997	1,041,762	986,350	899,966	787,973	750,253	676,828	666,552	566,315
Operations & Maintenance Expenses										
(in thousands of dollars)	**796,104**	770,073	789,516	720,957	653,993	561,396	508,524	461,101	447,270	401,778
Payments in Lieu of Taxes										
(in thousands of dollars)	**31,827**	30,094	28,217	27,851	24,810	22,426	21,398	20,241	19,693	18,591
Net Operating Revenues before Depreciation and Amortization										
(in thousands of dollars)	**262,282**	247,830	224,029	237,542	221,163	204,151	220,331	195,486	199,589	145,946
Net Income										
(in thousands of dollars)	**55,276**	54,829	54,440	40,047	46,557	79,186	89,489	84,290	82,171	24,844
Energy Sales										
(in megawatt-hours)										
Residential	**3,607,439**	3,595,316	3,602,973	3,644,400	3,361,672	3,486,858	3,546,116	3,374,053	3,356,196	3,054,576
Commercial	**3,561,707**	3,492,745	3,481,459	3,777,092	3,672,982	3,758,853	3,750,634	3,577,436	3,535,036	3,369,713
Industrial	**3,606,611**	3,670,346	3,698,719	3,427,710	3,039,396	2,877,282	2,759,087	2,664,743	2,644,634	2,630,038
Off-System Sales	**3,925,574**	3,671,978	4,631,175	5,552,645	5,534,803	3,003,888	2,858,004	2,486,483	2,502,433	3,646,043
Unbilled Sales	**26,221**	28,558	(85,917)	(24,109)	74,416	50,374	13,858	9,628	21,285	6,890
Total	**14,727,552**	14,458,943	15,328,409	16,377,738	15,683,269	13,177,255	12,927,699	12,112,343	12,059,584	12,707,260
Number of Customers										
(average per year)										
Residential	**311,921**	308,516	308,412	303,374	299,813	296,648	293,642	289,713	282,310	275,854
Commercial	**44,221**	43,589	43,564	43,225	43,134	42,867	42,214	41,488	40,665	39,834
Industrial	**193**	210	206	154	151	142	134	132	133	135
Off-System	**33**	35	41	38	34	32	35	37	39	45
Total	**356,368**	352,350	352,223	346,791	343,132	339,689	336,025	331,370	323,147	315,868
Cents Per kWh (average)										
Residential	**10.68**	10.12	9.37	9.22	8.77	7.82	7.51	7.40	7.07	6.95
Commercial	**8.61**	8.40	7.89	7.54	7.29	6.36	6.07	5.99	5.77	5.76
Industrial	**5.96**	5.38	5.05	4.83	4.62	3.82	3.64	3.55	3.46	3.40
Retail	**8.43**	7.94	7.42	7.26	6.96	6.13	5.93	5.81	5.58	5.48
Generating Capability										
(at year end)										
(in megawatts)	**3,237.0**	3,208.8	3,222.7	3,224.7	3,223.9	2,548.8	2,548.8	2,544.1	2,542.5	2,540.5
System Peak Load										
(in megawatts)	**2,339.4**	2,451.6	2,468.3	2,402.8	2,316.4	2,181.1	2,197.4	2,271.9	2,223.3	2,143.8
Net System Requirements										
(in megawatt-hours)										
Generated	**13,209,542**	12,855,389	13,807,712	15,870,513	15,263,983	12,477,032	12,274,660	11,341,827	11,180,808	12,235,044
Purchased and Net										
Interchanged	**(1,819,871)**	(1,529,643)	(2,576,167)	(4,428,059)	(4,627,627)	(1,864,214)	(1,738,833)	(1,268,780)	(1,148,903)	(2,716,242)
Net	**11,389,671**	11,325,746	11,231,545	11,442,454	10,636,356	10,612,818	10,535,827	10,073,047	10,031,905	9,518,802

Management's Discussion and Analysis (Unaudited)

USING THIS FINANCIAL REPORT

The Financial Report for the Omaha Public Power District (OPPD or Company) includes this Management's Discussion and Analysis, Financial Statements and Notes to the Financial Statements. The basic Financial Statements consist of the Statement of Net Position, the Statement of Revenues, Expenses and Changes in Net Position and the Statement of Cash Flows. The Financial Statements have been prepared in accordance with generally accepted accounting principles for proprietary funds of governmental entities. Questions concerning any of the information provided in this report should be directed to Investor Relations, 402-636-3286.

Management's Discussion and Analysis (MD&A) – This unaudited information provides an objective and easily readable analysis of OPPD's financial activities based on currently known facts, decisions or conditions. In the MD&A, financial managers present both short-term and long-term analyses of the Company's activities. The MD&A should be read in conjunction with the Financial Statements and related Notes. This document contains forward-looking statements based on current plans.

Statement of Net Position – This statement reports resources with service capacity (assets) and obligations to sacrifice resources (liabilities). Deferrals result from outflows and inflows of resources that have already taken place but are not recognized in the financial statements as expenses and revenues because they relate to future periods. Net Position is the residual interest in the Company. On the Statement of Net Position, the sum of assets and deferred outflows equals the sum of liabilities, deferred inflows and net position. This statement facilitates the assessment and evaluation of liquidity, financial flexibility and capital structure.

Statement of Revenues, Expenses and Changes in Net Position – All revenues and expenses are accounted for in this statement. This statement measures the activities for the year and can be used to determine whether the rates, fees and other charges are adequate to recover expenses.

Statement of Cash Flows – This statement reports all cash receipts and payments summarized by net changes in cash from operating, capital and related financing and investing activities.

Notes to the Financial Statements (Notes) – These notes provide additional detailed information to support the Financial Statements.

Statistics – This unaudited section provides additional comparison information.

OVERVIEW

The financial position and results of operations were similar for 2013 and 2012. Fort Calhoun Station (FCS) was in an outage during both of these years and resumed operations on December 21, 2013. This extended outage had an adverse impact on off-system sales revenues and operating expenses. OPPD lessened the impact on customer-owners through insurance recoveries, the use of regulatory accounting and cost reductions. The most significant cost reductions in 2013 were from lower prices for coal transportation and reductions in employee benefit expenses. The following sections include more detailed information on financial activities.

FINANCIAL POSITION AND RESULTS OF OPERATIONS

The following table summarizes OPPD's financial position as of December 31 (in thousands).

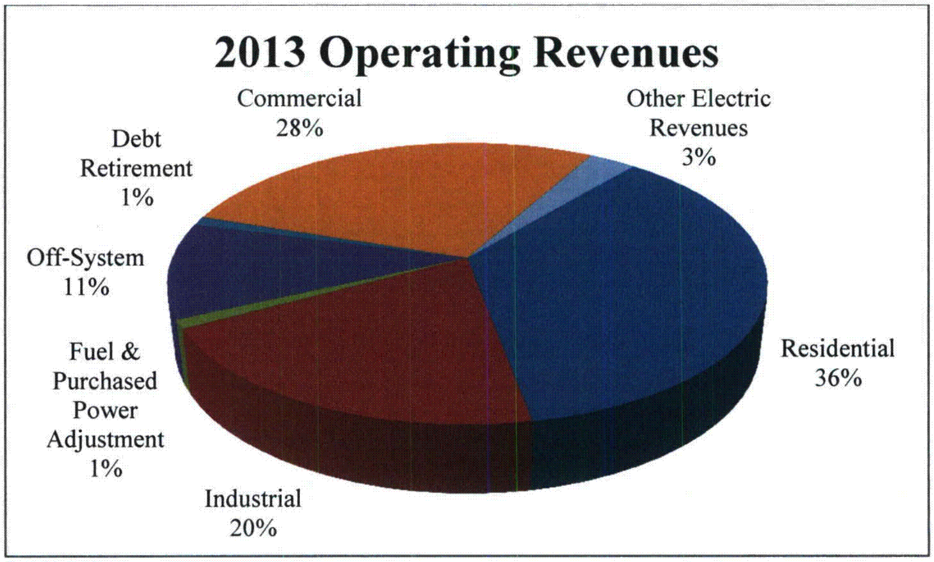
Condensed Statements of Net Position	**2013**	**2012**
Current Assets	$ 700,882	$ 809,696
Other Long-Term Assets and Special Purpose Funds	757,626	683,886
Capital Assets	3,359,141	3,342,731
Total Assets	4,817,649	4,836,313
Deferred Outflows of Resources	29,310	33,502
Total Assets and Deferred Outflows	$ 4,846,959	$ 4,869,815
Current Liabilities	$ 222,405	$ 385,947
Long-Term Liabilities	2,717,966	2,615,556
Total Liabilities	2,940,371	3,001,503
Deferred Inflows of Resources	37,000	54,000
Net Position	1,869,588	1,814,312
Total Liabilities, Deferred Inflows and Net Position	$ 4,846,959	$ 4,869,815

The following table summarizes OPPD's operating results for the years ended December 31 (in thousands).

Operating Results	**2013**	**2012**
Operating Revenues	$ 1,090,213	$ 1,047,997
Operating Expenses	(958,338)	(928,961)
Operating Income	131,875	119,036
Other Income	20,956	28,418
Interest Expense	(97,555)	(92,625)
Net Income	$ 55,276	$ 54,829

Operating Revenues

The following chart illustrates 2013 operating revenues by category and percentage of the total. Other electric revenues include connection charges, late payment charges, rent from electric property, wheeling fees, insurance recoveries for prior years and miscellaneous revenues.



2013 Compared to 2012 – Total operating revenues were $1,090,213,000 for 2013, an increase of $42,216,000 or 4.0% over 2012 operating revenues of $1,047,997,000.

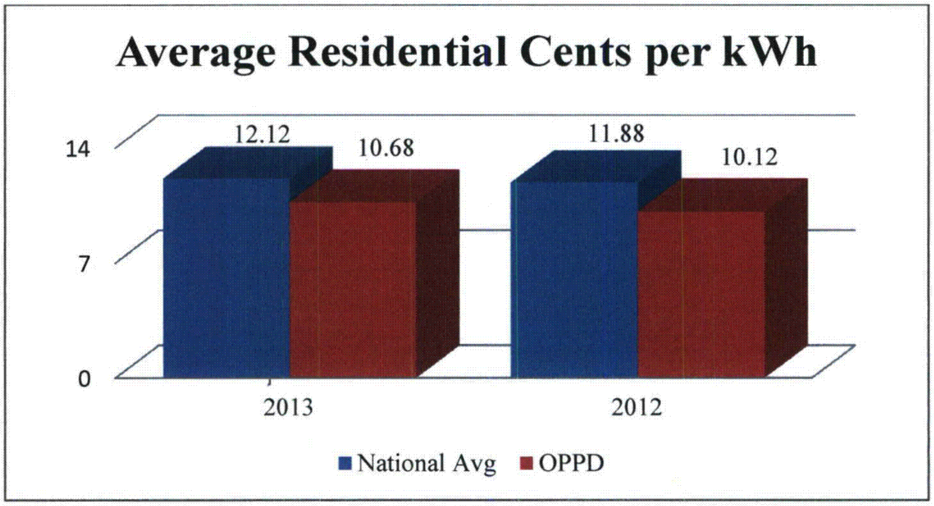
- Revenues from retail sales were $942,291,000 for 2013, an increase of $72,385,000 or 8.3% over 2012 revenues of $869,906,000. The change in retail revenues was primarily due to higher energy prices and an increase in the adjustment for the under-recovery of fuel and purchased power expenses.
- Revenues from retail sales included $17,000,000 in transfers from the Debt Retirement Reserve in both 2013 and 2012.
- Revenues from off-system sales were $118,268,000 for 2013, a decrease of $4,923,000 or 4.0% from 2012 revenues of $123,191,000. The decrease was primarily due to the expiration of a large participation sales contract.
- Other Electric Revenues were $29,654,000 for 2013, a decrease of $25,246,000 or 46.0% from 2012 revenues of $54,900,000. The decrease was primarily due to insurance recoveries received in 2012.

Cents per kWh

The Company strives to manage costs and maximize the public power advantage of low-cost and reliable service.

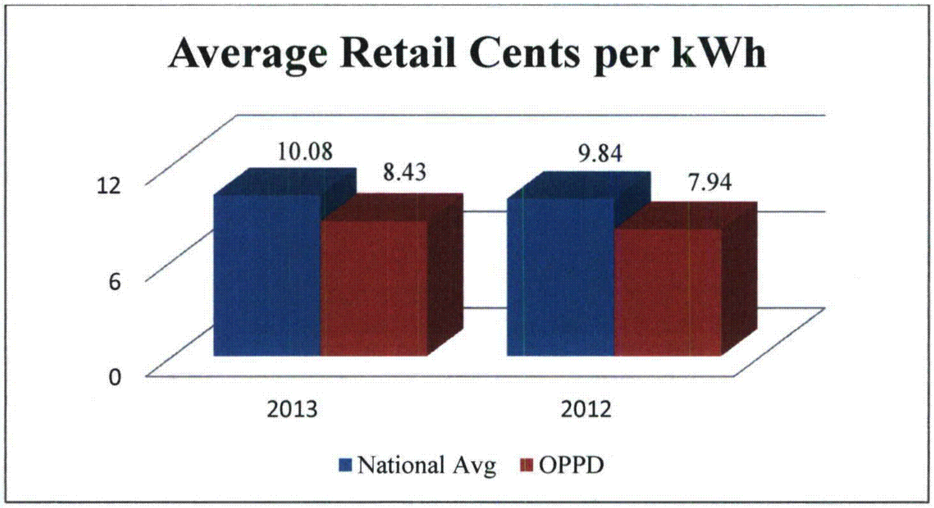
Residential customers paid an average of 10.68 and 10.12 cents per kilowatt-hour (kWh) in 2013 and 2012, respectively. The national average residential cents per kWh according to the Energy Information Administration (EIA), U.S. Department of Energy, was 12.12 for 2013 (preliminary year-to-date December 2013) and 11.88 cents per kWh for 2012. Based on the preliminary EIA data for 2013, OPPD residential rates were 11.9% below the national average.

The following chart illustrates the Company's average residential cents per kWh compared to the national average.



Retail customers paid an average of 8.43 and 7.94 cents per kWh in 2013 and 2012, respectively. The national average retail cents per kWh according to the EIA, was 10.08 for 2013 (preliminary year-to-date December 2013) and 9.84 cents per kWh for 2012. Based on the preliminary EIA data for 2013, OPPD retail rates were 16.4% below the national average.

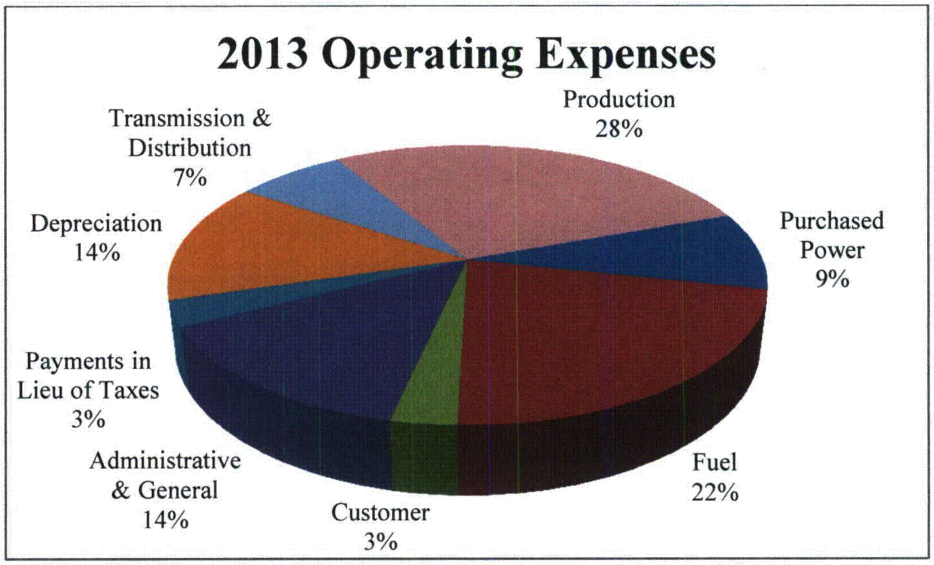
The following chart illustrates the Company's average retail cents per kWh compared to the national average.



General rate adjustments of 7.3% and 4.5% were implemented in January 2013 and 2012, respectively, due to increased operating costs. The adjustments to the Fuel and Purchased Power Adjustment (FPPA) were a decrease of 0.4% for 2013 and an increase of 1.4% for 2012. Cost-containment, the use of regulatory accounting and other risk management efforts have limited these rate adjustments. There were no rate adjustments implemented in January 2014.

Operating Expenses

The following chart illustrates 2013 operating expenses by expense classification and percentage of the total.



2013 Compared to 2012 - Total operating expenses were $958,338,000 for 2013, an increase of $29,377,000 or 3.2% over 2012 operating expenses of $928,961,000.

- Fuel expense decreased $21,024,000 or 8.9% from 2012, primarily due to lower coal transportation costs resulting from the renegotiation of the contract.
- Purchased Power expense increased $10,173,000 or 13.8% over 2012, primarily due to additional renewable energy purchases.
- Production expense increased $36,565,000 or 16.0% over 2012, primarily due to higher operations and maintenance expenses incurred at FCS.
- Transmission expense increased $2,014,000 or 9.2% over 2012, primarily due to higher transmission and regulatory expenses and fees.
- Distribution expense increased $7,107,000 or 19.2% over 2012, primarily due to additional charges for supporting services.
- Customer Accounts expense increased $1,216,000 or 8.7% over 2012, primarily due to additional credit card processing fees and postage expenses.
- Customer Service and Information expense decreased $1,234,000 or 7.5% from 2012, primarily due to decreased incentive payments for sustainability projects.

- Administration and General expense decreased $8,786,000 or 6.2% from 2012, primarily due to lower employee benefit costs.
- Depreciation and Amortization increased $1,613,000 or 1.3% over 2012, due to additional depreciation for capital additions.
- Payments in Lieu of Taxes expense increased $1,733,000 or 5.8% over 2012, due to higher retail revenues.

Other Income (Expenses)

Other income (expenses) totaled $20,956,000 in 2013, a decrease of $7,462,000 from 2012 other income (expenses) of $28,418,000. Other - net was $4,131,000 lower in 2013, primarily due to grants from the Federal Emergency Management Agency in 2012. Investment income was $2,380,000 lower than 2012 investment income of $2,041,000 due to an overall decrease in the fair market value of fixed income investments. Long-term interest rates have been rising resulting in lower bond prices and yields.

Allowances for Funds Used During Construction (AFUDC) totaled $13,334,000 in 2013, a decrease of $900,000 from 2012 AFUDC of $14,234,000 due to a lower interest rate.

A variety of products and services are offered, which provide value both to the customer and the Company. These products include Residential and Commercial Surge Protection, In-Home Electrical Protection Plan, ECO 24/7, Energy Information Services and Geothermal Loop Heat Exchanges. Offering these products and services provides opportunities to build strong relationships with customers by helping them efficiently and economically meet their energy needs.

Income from products and services was $3,228,000 for 2013, a decrease of $51,000 from 2012 income from products and services of $3,279,000. This decrease was primarily due to less income from the sale of Geothermal Loop Heat Exchange products.

Interest Expense

Interest expense was $97,555,000 for 2013, an increase of $4,930,000 over 2012 interest expense of $92,625,000. This increase was due to incurring a full year of interest expense for the 2012 Series A Electric System Revenue Bonds in 2013.

Net Income

Net income, after revenue adjustments for changes to the Debt Retirement Reserve, was $55,276,000 and $54,829,000 for 2013 and 2012, respectively. Changes to the Debt Retirement Reserve resulted in operating revenues and net income increasing by $17,000,000 in 2013 and 2012.

CAPITAL PROGRAM

The Company's utility plant assets include production, transmission and distribution, and general plant facilities. The following table summarizes the balance of capital assets as of December 31 (in thousands).

	2013	2012
Electric plant	$4,782,357	$4,692,215
Construction work in progress	404,042	394,415
Nuclear fuel - at amortized cost	101,769	100,765
Accumulated depreciation and amortization	(1,929,027)	(1,844,664)
Total utility plant - net	$3,359,141	$3,342,731

Electric system requirements, including the identification of future capital investments, are routinely evaluated to ensure current and future load requirements are serviced by a reliable and diverse power supply. Capital investments are financed with revenues from operations, bond proceeds, investment income and cash on hand. Certain capital expenditures were deferred, where possible, due to the FCS outage which concluded in 2013. Capital expenditures were $6,905,000 under budget for 2013.

The following table shows actual capital program expenditures, including allowances for funds used during construction, for the last two years and budgeted expenditures for 2014 (in thousands).

	Budget	Actual	
Capital Program	**2014**	**2013**	**2012**
Production	$ 72,746	$ 83,504	$ 89,537
Transmission and distribution	85,138	54,503	74,011
General	15,238	21,069	16,640
Total	$173,122	$159,076	$180,188

Production expenditures include equipment to comply with increasing environmental regulations. A natural gas pipeline and other equipment will be placed in service in 2014 at the Nebraska City Station to allow the use of natural gas as an alternative to fuel oil for a start-up and stabilization fuel source.

Transmission and distribution expenditures include the installation of new technologies and substation and distribution facilities to maintain system reliability, enhance efficiency and respond to load growth.

General plant expenditures include the purchase of construction and transportation equipment and information technology upgrades.

Significant capital projects planned for 2014, ordered by highest planned expenditures, include the following.

- Customer substation work – This is a project to support work being completed at Offutt Air Force Base.
- Fort Calhoun Station Remote Spent Fuel Pool Monitoring – This project will ensure continuous power at the station during extreme natural events.
- Fort Calhoun Station Security Force on Force structure improvements – This project will reinforce the physical protection of the plant.
- Fort Calhoun Station Internal Containment Structure beam reinforcements – This is the design of additional reinforcements prescribed by the Nuclear Regulatory Commission (NRC) to ensure the facility is protected against a catastrophic natural disaster.
- Distribution work – This is to support the business needs of a customer.
- Construction Equipment and Heavy Truck Replacement – This is normal replacement of general construction equipment.
- Sarpy County Station Unit No. 3 Overhaul – This is the overhaul of a gas unit at the station.

CASH AND LIQUIDITY

Cash Flows

There were increases in cash of $32,366,000 and $29,825,000 during 2013 and 2012, respectively. The following table illustrates the cash flows by activities for the years ended December 31 (in thousands).

Cash Flows	**2013**	**2012**
Cash Flows from Operating Activities	$ 168,708	$ 151,733
Cash Flows from Capital and Related Financing Activities	(274,163)	(8,072)
Cash Flows from Investing Activities	137,821	(113,836)
Change in Cash and Cash Equivalents	$ 32,366	$ 29,825

Cash flows from operating activities consist of transactions involving changes in current assets, current liabilities and other transactions that affect operating income.

- Cash flows for 2013 increased $16,975,000 over 2012, primarily due to an increase in cash received from retail customers and insurance companies. This was partially offset by an increase in cash paid to off-system counterparties for additional wind energy.

Cash flows from capital and related financing activities consist of transactions involving long-term debt and the acquisition and construction of capital assets.

- Cash flows used for 2013 increased $266,091,000 over 2012, primarily due to proceeds from long-term borrowings in 2012 which reduced the cash flows used in 2012.

Cash flows from investing activities consist of transactions involving purchases and maturities of investment securities and investment income.

- Cash flows for 2013 increased $251,657,000 over 2012, primarily due to more maturities and sales of investments than purchases in 2013.

Financing

Sufficient liquidity is maintained to ensure working capital is available for normal operational needs and unexpected but predictable risk events. OPPD's liquidity includes cash, marketable securities and a line of credit. Bond offerings also provide a significant source of liquidity for capital investments not funded by revenues from operations.

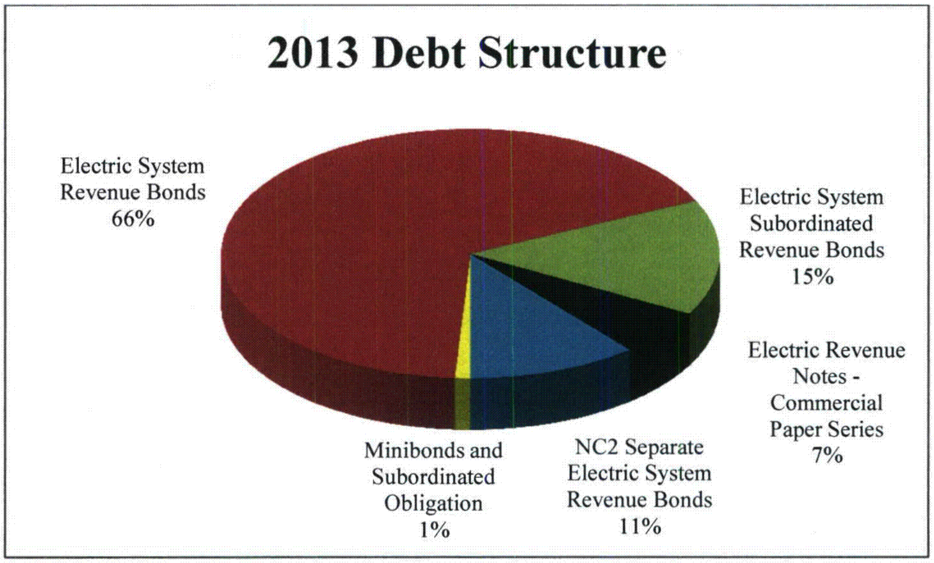
The financing plan optimizes the debt structure to ensure capital needs are financed, liquidity needs are achieved and the Company's strong financial position is maintained. The 2014 financing plan does not include any bond issues; however, the Company will continue to monitor refunding opportunities to achieve any potential interest cost savings for customer-owners.

There were no bond issuances in 2013. The Company made repayments of $26,125,000 of Electric System Revenue Bonds and $169,000 of Minibonds during 2013. Repayments for the Electric System Revenue Bonds included a principal payment of $9,385,000 for the early call of a portion of the 1993 Series C term bonds due February 1, 2014.

Two Electric System Revenue Bond issues totaling $499,370,000 were completed during 2012. An issue totaling $226,715,000 was used to refund outstanding bonds with higher interest rates, and a second issue totaling $272,655,000 was used to finance capital expenditures. In addition, repayments of $52,460,000 of Electric System Revenue Bonds, $460,000 of Electric System Subordinated Revenue Bonds and $143,000 of Minibonds were made in 2012. Repayments for the Electric System Revenue Bonds included principal payments of $8,850,000 for the early call of a portion of the 1993 Series C term bonds due February 1, 2013 and $13,990,000 for the early redemption of the 2002 Series B serial bonds due February 1, 2013.

The Company renewed a Credit Agreement for $250,000,000 in 2013. This supports the Commercial Paper Program in addition to providing another source of working capital, if needed. There were no amounts outstanding under this Credit Agreement as of December 31, 2013 or 2012. There was $150,000,000 of commercial paper outstanding as of December 31, 2013 and 2012.

The following chart illustrates the debt structure and percentage of the total as of December 31, 2013.



Debt Service Coverage for Electric System Revenue Bonds

Debt service coverage for the Electric System Revenue Bonds was 2.25 and 2.21 in 2013 and 2012, respectively. OPPD's senior lien bond indenture provides that additional bonds may not be issued unless estimated net receipts for each future year shall equal or exceed 1.4 times the debt service on all Electric System Revenue Bonds outstanding, including the additional bonds being issued. Transactions in 2013 and 2012 for the NC2 Separate Electric System were not included in the calculation because the Electric System Revenue Bonds are not secured by the Separate System. The Company is in compliance with all debt covenants.

Debt Ratio

The debt ratio is a measure of financial solvency and represents the share of debt to total capitalization (debt and net position). This ratio does not include the NC2 Separate Electric System Revenue Bonds since this debt is secured by revenues of the NC2 Participation Power Agreements. The debt ratio was 52.0% and 53.1% as of December 31, 2013 and 2012, respectively.

Ratings

High credit ratings allow the Company to borrow funds at more favorable interest rates. Both quantitative (financial strength) and qualitative (business and operating characteristics) factors are considered by the credit rating agencies in establishing a company's credit rating. The ratings received from Standard & Poor's Ratings Services (S&P) and Moody's Investors Service (Moody's), independent bond rating agencies for the latest bond issues, were among the highest ratings granted to electric utilities and confirm the agencies' assessment of the Company's strong ability to meet its debt service requirements. Moody's changed its ratings for OPPD's senior lien debt from Aa1 to Aa2 and for subordinated debt from Aa2 to Aa3, primarily due to FCS challenges and potential environmental

compliance costs for the fossil stations. Both Moody's and S&P have stable outlooks for OPPD's credit ratings.

The following table summarizes credit ratings in effect on December 31, 2013.

	S&P	Moody's
Electric System Revenue Bonds	AA	Aa2
Electric System Subordinated Revenue Bonds (including PIBs) *	AA-	Aa3
Electric Revenue Notes - Commercial Paper Series	A-1+	P-1
Minibonds *	AA-	Aa3
NC2 Separate Electric System Revenue Bonds (2005A, 2006A) *	A	A1
NC2 Separate Electric System Revenue Bonds (2008A)	A	A1

* *Payment of the principal and interest on the Electric System Subordinated Revenue Bonds, Minibonds and NC2 Separate Electric System Revenue Bonds 2005 Series A and 2006 Series A, when due, is insured by financial guaranty bond insurance policies. PIBs are Periodically Issued Bonds, which are another type of Electric System Subordinated Revenue Bond.*

RISK MANAGEMENT

Risk Management Practices

An Enterprise Risk Management (ERM) program is used to identify, quantify, prioritize and manage the risks of the Company. Specific risk-mitigation plans and procedures are maintained to provide focused and consistent efforts to mitigate various risk exposures. Several cross-functional risk committees are utilized to discuss and analyze potential risks that could hinder the achievement of OPPD's strategic objectives. Additionally, an Executive ERM Committee has been established to specifically discuss risk-related issues at the senior management level of the Company. An overview of the ERM program is provided to the Board of Directors annually.

Power marketing and fuel purchase activities are conducted within the normal course of business. Risks associated with power marketing and fuel contracting are managed within a risk management control framework. Fuel expense represents a significant portion of generation costs and affects the ability to generate and market competitively priced power. A risk-management working group is responsible for identifying, measuring and mitigating various risk exposures related to power marketing and fuel purchase activities.

OPPD participates in the wholesale marketplace with other electric utilities and power marketers for off-system energy sales. The Company must be able to offer energy at competitive prices and obtain transmission services to successfully compete in this market. Energy market prices may fluctuate substantially in a short period of time due to changes in the supply and demand of electricity. Counterparty credit risks are monitored closely on an ongoing basis. The Company's energy trading and marketing practices and processes have been modified for the implementation of the Integrated Marketplace in the Southwest Power Pool (SPP) in 2014. The risks associated with these changes have been identified and plans have been established for their mitigation.

A Rate Stabilization Reserve was established in 1999 to assist in stabilizing retail electric rates. Funds from this reserve were used to help finance higher fuel costs and unexpected energy purchases in 2011

due to the extended outage at FCS to lessen the impact on customer-owners. The fund was replenished with FPPA recoveries and insurance proceeds in 2013 and 2012. The balance of the fund was $32,000,000 and $24,612,000 as of December 31, 2013 and 2012, respectively. The balance of the reserve was maintained at $32,000,000 as of December 31, 2013 and 2012.

A Debt Retirement Reserve was established in 2003 to assist in managing the long-term risks associated with significant capital expenditures and related debt issuances. This reserve is used to meet challenges in retiring debt and maintaining adequate debt service coverage ratios. The reserve was used to provide additional revenues and funds of $17,000,000 each in 2013 and 2012. The balance of the fund was $0 and $14,000,000 as of December 31, 2013 and 2012, respectively. The balance of the reserve was $0 and $17,000,000 as of December 31, 2013 and 2012, respectively.

The Company promotes ethical business practices and the highest standards in the reporting and disclosure of financial information. The Sarbanes-Oxley Act (Act) is intended to strengthen corporate governance of publicly traded companies. As a public utility, the Company is not required to comply with the Act, but the application of these requirements, where appropriate, ensures continued public trust in OPPD, protects the interest of its stakeholders and is a sound business practice. One of the most significant requirements of the Act pertains to management's documentation and assessment of internal controls. The Company's management assesses internal controls for significant business processes that impact financial reporting. This assessment includes documenting procedures, risks and controls for these processes and assessing the effectiveness and operation of the internal controls. In addition, the Company contracts with an independent third party to administer the receipt, communication and retention of employee concerns regarding business and financial practices.

Other Reserves

Other reserves are maintained to recognize potential liabilities that arise in the normal course of business. Additional information about other reserves follows.

- The Uncollectible Accounts Reserve is established for estimated uncollectible accounts from both retail and off-system sales. Accounts Receivable is reported net of the $1,000,000 reserve for retail sales. A $5,000,000 reserve for off-system sales was established by the Board of Directors. This reserve is separately reported as a deferred inflow on the Statement of Net Position.
- The Workers' Compensation and Public Liability Reserves are established for the estimated liability for current workers' compensation and public liability claims.
- The Incurred But Not Presented Reserve is an insurance reserve that is required by state law because the Company is self-insured for health care costs. The reserve is based on health insurance claims that have been incurred but not yet presented for payment.

REGULATORY AND ENVIRONMENTAL UPDATES

Fort Calhoun Station Update

FCS was taken out of service for a normal refueling outage in April 2011. Outage activities were suspended in June 2011 to protect facilities from rising river levels caused by the release of record amounts of water from dams along the Missouri River by the U.S. Army Corps of Engineers. The NRC placed FCS into a special category of their inspection manual, Chapter 0350, in December 2011. This chapter is for nuclear plants that are in extended shutdowns with performance issues. OPPD contracts with Exelon Generation Company, LLC, the largest operator of nuclear stations in the United States, for operational and managerial support services. FCS resumed operations on December 21, 2013, after satisfactorily completing NRC requirements and inspections.

The Board of Directors authorized management to establish a regulatory asset for certain recovery costs, with amortization over a 10-year period commencing after the resumption of operations. Qualifying recovery costs will continue to be deferred until FCS's regulatory rating is increased to a more favorable NRC regulatory category. The balance of this regulatory asset was $138,362,000 and $70,627,000 as of December 31, 2013 and 2012, respectively.

SPP Integrated Marketplace and Transmission Access

OPPD became a transmission-owning member of SPP, and all of the Company's transmission facilities were placed under the SPP open access transmission tariff on April 1, 2009. In addition to tariff administration services, SPP also provides reliability coordination services, generation reserve sharing, energy imbalance market services and transmission planning services to OPPD and SPP's other transmission-owning members.

The SPP Board of Directors approved expansion of the current real-time Energy Imbalance Market (Day 1) into a Day 2 Market. The SPP Day 2 Market, also known as the Integrated Marketplace (IM), includes Day-Ahead Markets and Real-Time Markets. It also includes Ancillary Services and Transmission Congestion Rights Markets. The IM went live on March 1, 2014. SPP is now the Consolidated Balancing Authority, relieving OPPD of these responsibilities.

The IM provides a more transparent market by which load is served by the most efficient and economical generation, while maintaining the reliability of the grid. The market mechanism rewards low cost, flexible and reliable providers of electricity. OPPD's generation is in competition with other generation owners to serve load across the SPP footprint. A cross-functional project team was launched in December 2011 to prepare for the IM. Individual task teams addressed related functional areas to ensure that systems, policies and personnel were ready for the transition and able to operate effectively in the new market.

A 180-mile 345-kilovolt power line being built by OPPD and Kansas City Power and Light (Midwest Transmission Project) will run from a substation at the Nebraska City Station to Sibley, Missouri. This

project is one of several priority projects as determined by SPP and is expected to relieve congestion on the region's transmission system; improve reliability on the nation's energy grid; and improve opportunities for wind energy distribution. The final route was selected in July of 2013 after a year-long process involving 20 public meetings. Construction is expected to begin in 2015 with a planned summer 2017 in-service date.

Renewable Capability including Purchased Power Contracts

Renewable portfolio standards are currently mandated in several states but not in Nebraska. The Board of Directors has established a proactive goal to provide 10% of retail energy from renewable sources by 2020. The percentage of renewable energy increased to 6.5% in 2013 from 5.3% in 2012 and is expected to increase to 15.1% in 2014. A purchased power contract with the Western Area Power Administration provides 86 MW of hydro power that is excluded from the goal.

The following table shows the renewable generation owned or purchased and future capability (in MW).

		Capability
OPPD Owned Generation		
	Elk City Station (landfill-gas)	6.2
	Valley Station (wind)	0.7
	Subtotal OPPD Owned Generation	6.9
Purchased Wind Generation		
	Ainsworth	10.0
	Elkhorn Ridge	25.0
	Flat Water	60.0
	Petersburg	40.5
	Broken Bow I	18.0
	Crofton Bluffs	13.6
	Subtotal Purchased Wind Generation	167.1
Total Renewable Generation as of December 31, 2013		174.0
2014 Purchased Wind Generation		
	Broken Bow II	45.0
	Prairie Breeze	200.6
	Subtotal 2014 Purchased Wind Generation	245.6
2017 Purchased Wind Generation		
	Grande Prairie	400.0
Total Expected Renewable Generation as of December 31, 2017		819.6

Environmental Matters

Environmental matters can have a significant impact on operations and financial results. OPPD complies with all applicable state and federal environmental rules and regulations. The items mentioned below include proposed, enacted or enforceable laws, rules and regulations.

The Environmental Protection Agency (EPA) finalized the Mercury and Air Toxics Standard (MATS) on December 16, 2011. Compliance with this rule will be necessary by April 16, 2015. An additional year was granted by local permitting agencies to allow for pilot testing, modeling, evaluation and to facilitate installation of pollution control equipment, if necessary. Various generation options have been modeled due to the impact of MATS and other environmental regulations. Pilot testing of Dry Sorbent Injection and Activated Carbon Injection has been conducted, and the results are being analyzed to determine the optimal generating options. The Washington D.C. Circuit Court heard challenges to the MATS rule on December 10, 2013.

The EPA published the Cross-State Air Pollution Rule (CSAPR) on August 8, 2011, to improve air quality by reducing power plant emissions contributing to ozone and fine-particle pollution in other states. Specifically, this proposal would have required significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NOx). CSAPR established a cap-and-trade system with state and unit specific allowance allocations to achieve desired emission reductions for SO_2 and NOx. Implementation of Phase I of the final rule was scheduled to begin in 2012, but the United States Court of Appeals for the District of Columbia issued an order on December 30, 2011, staying CSAPR pending judicial review. On August 21, 2012, the federal court vacated CSAPR stating the rule exceeds the statutory authority of the EPA. The U.S. Supreme Court heard oral arguments on December 10, 2013, in review of the federal court's invalidation of CSAPR. In the interim, the EPA will continue administering the Clean Air Interstate Rule (CAIR), the predecessor to CSAPR pending the promulgation of a valid replacement rule. The State of Nebraska is not covered by CAIR; therefore, OPPD remains unaffected at this time.

The EPA announced its plan to reduce carbon pollution from electric generating stations on September 20, 2013. The proposed standards are the first uniform national limits on the amount of carbon emissions that future stations will be allowed. The EPA will be engaging with states and others, including the power sector, environmental groups and the public, to identify approaches shown to reduce carbon emissions. A proposed rule for controlling carbon emissions from existing generating stations is expected in 2014 with a final rule expected in 2015. OPPD continually monitors local, state and federal agencies for rules that may change or require further reductions of emissions.

Federal Energy Legislation

The 113th Congress began its two-year legislative session in January 2013. During the previous Congress, the House of Representatives passed legislation that would block efforts by the EPA to regulate greenhouse gas emissions under the Clean Air Act. In 2012, the House of Representatives also passed legislation to block or delay other EPA regulatory proposals that are aimed primarily at fossil-fired electric generation facilities. The Senate did not pass similar legislation. Given the same

leadership, the Senate will likely continue to block similar legislation passed by the House through the end of this Congressional Legislative Session, which ends in December 2014.

Efforts on energy legislation are likely to be very limited and would focus on market-based approaches that would help create jobs and grow the economy as well as possibly addressing the issue of long-term storage of high-level nuclear waste. Energy and environmental initiatives such as carbon cap-and-trade and climate change legislation could result in substantial rate increases if enacted into law. OPPD continues to monitor the status of energy and climate-change legislation in Congress and provides input through public power industry groups and the Nebraska Congressional Delegation.

State of Nebraska Energy Legislation

The Nebraska Legislature enacted Legislative Bill 646 (L.B. 646), Change Election Provisions for Public Power Districts during the 2013 session. L.B. 646 provides that public power districts create subdivisions substantially equal in population for its board elections. OPPD was the only district affected by this change. The Board of Directors changed from three to eight distinct district subdivisions in support of this legislation. The Nebraska Power Review Board approved the amendment to OPPD's charter, and the new subdivisions were effective January 1, 2014.

The Legislature also enacted Legislative Bill 388 (L.B. 388), Change Provisions Relating to Public Power and Provide for Construction of Certain Transmission Lines in 2012. L.B. 388 provides electric transmission owners, who belong to a Regional Transmission Organization (RTO), the right of first refusal to complete transmission projects in Nebraska that have been approved by the RTO. The purpose is to clarify that public power entities in Nebraska have the first right to construct, own and maintain approved transmission lines.

The Nebraska Legislature enacted Legislative Bill 901 (L.B. 901), during the 2000 session, which implemented recommendations to determine whether retail competition would be beneficial for Nebraska ratepayers. Reports for the Governor and Legislature on the conditions in the electric industry indicating whether retail competition would be beneficial for Nebraska's citizens are prepared at the request of the Nebraska Power Review Board. All of the conditions for retail competition have not been met, based on the findings from the latest report, dated October 2010.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results could differ from those estimates.

Those judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may have a significant effect on the operation of the business and on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies has not changed.

The following is a list of accounting policies that are significant to OPPD's financial condition and results of operation and require management's most significant, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policies	**Judgments/Uncertainties Affecting Application**
Environmental Matters and Pollution Remediation Obligations	• Approved methods for cleanup • Governmental regulations and standards • Cost estimates for future remediation options
Nuclear Plant Decommissioning	• Cost estimates for future decommissioning • Availability of facilities for waste disposal • Approved methods for waste disposal • Useful life of Fort Calhoun Station
Regulatory Mechanisms and Cost Recovery	• External regulatory requirements • Anticipated future regulatory decisions and their impact
Retirement Plan and Other Post Employment Benefits	• Assumptions used in computing the actuarial liability, including expected rate of return on Plan assets • Plan design
Self-Insurance Reserves for Claims for Employee-related Healthcare Benefits, Workers Compensation and Public Liability	• Cost estimates for claims • Assumptions used in computing the liabilities
Uncollectible Accounts Reserve	• Economic conditions affecting customers • Assumptions used in computing the liabilities
Unbilled Revenue	• Estimates for customer energy use and prices
Depreciation and Amortization Rates of Assets	• Estimates for approximate useful lives

Statistics (Unaudited)

	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
Total Utility Plant (at year end) (in thousands of dollars)	**5,288,168**	5,187,395	5,027,093	4,865,417	4,678,449	4,561,815	4,259,501	4,166,997	3,656,433	3,363,909
Total Indebtedness (at year end) (in thousands of dollars)	**2,267,277**	2,296,305	2,085,540	2,011,969	1,937,704	1,902,403	1,866,472	1,565,807	1,133,171	894,020
Operating Revenues (in thousands of dollars)										
Residential	**385,171**	362,105	337,053	335,294	292,887	271,935	267,042	249,174	237,798	211,913
Commercial	**306,719**	292,296	274,102	284,400	265,668	238,496	228,060	213,314	204,314	194,684
Industrial	**213,742**	197,225	186,417	164,621	139,865	109,827	100,239	94,109	90,344	90,987
Off-System Sales	**118,268**	123,191	159,732	184,374	158,354	127,676	110,399	96,500	120,030	109,523
FPPA Revenue	**15,169**	(3,237)	35,345	269	—	—	—	—	—	—
Unbilled Revenues	**4,490**	4,517	(4,239)	1,232	7,449	3,391	1,742	2,527	630	(1,134)
Provision for Debt Retirement	**17,000**	17,000	24,000	(13,000)	13,000	20,000	27,000	(15,000)	—	(55,000)
Other Electric Revenues	**29,654**	54,900	29,352	29,160	22,743	16,648	15,771	36,204	13,436	15,342
Total	**1,090,213**	1,047,997	1,041,762	986,350	899,966	787,973	750,253	676,828	666,552	566,315
Operations & Maintenance Expenses (in thousands of dollars)	**796,104**	770,073	789,516	720,957	653,993	561,396	508,524	461,101	447,270	401,778
Payments in Lieu of Taxes (in thousands of dollars)	**31,827**	30,094	28,217	27,851	24,810	22,426	21,398	20,241	19,693	18,591
Net Operating Revenues before Depreciation and Amortization (in thousands of dollars)	**262,282**	247,830	224,029	237,542	221,163	204,151	220,331	195,486	199,589	145,946
Net Income (in thousands of dollars)	**55,276**	54,829	54,440	40,047	46,557	79,186	89,489	84,290	82,171	24,844
Energy Sales (in megawatt-hours)										
Residential	**3,607,439**	3,595,316	3,602,973	3,644,400	3,361,672	3,486,858	3,546,116	3,374,053	3,356,196	3,054,576
Commercial	**3,561,707**	3,492,745	3,481,459	3,777,092	3,672,982	3,758,853	3,750,634	3,577,436	3,535,036	3,369,713
Industrial	**3,606,611**	3,670,346	3,698,719	3,427,710	3,039,396	2,877,282	2,759,087	2,664,743	2,644,634	2,630,038
Off-System Sales	**3,925,574**	3,671,978	4,631,175	5,552,645	5,534,803	3,003,888	2,858,004	2,486,483	2,502,433	3,646,043
Unbilled Sales	**26,221**	28,558	(85,917)	(24,109)	74,416	50,374	13,858	9,628	21,285	6,890
Total	**14,727,552**	14,458,943	15,328,409	16,377,738	15,683,269	13,177,255	12,927,699	12,112,343	12,059,584	12,707,260
Number of Customers (average per year)										
Residential	**311,921**	308,516	308,412	303,374	299,813	296,648	293,642	289,713	282,310	275,854
Commercial	**44,221**	43,589	43,564	43,225	43,134	42,867	42,214	41,488	40,665	39,834
Industrial	**193**	210	206	154	151	142	134	132	133	135
Off-System	**33**	35	41	38	34	32	35	37	39	45
Total	**356,368**	352,350	352,223	346,791	343,132	339,689	336,025	331,370	323,147	315,868
Cents Per kWh (average)										
Residential	**10.68**	10.12	9.37	9.22	8.77	7.82	7.51	7.40	7.07	6.95
Commercial	**8.61**	8.40	7.89	7.54	7.29	6.36	6.07	5.99	5.77	5.76
Industrial	**5.96**	5.38	5.05	4.83	4.62	3.82	3.64	3.55	3.46	3.40
Retail	**8.43**	7.94	7.42	7.26	6.96	6.13	5.93	5.81	5.58	5.48
Generating Capability (at year end) (in megawatts)	**3,237.0**	3,208.8	3,222.7	3,224.7	3,223.9	2,548.8	2,548.8	2,544.1	2,542.5	2,540.5
System Peak Load (in megawatts)	**2,339.4**	2,451.6	2,468.3	2,402.8	2,316.4	2,181.1	2,197.4	2,271.9	2,223.3	2,143.8
Net System Requirements (in megawatt-hours)										
Generated	**13,209,542**	12,855,389	13,807,712	15,870,513	15,263,983	12,477,032	12,274,660	11,341,827	11,180,808	12,235,044
Purchased and Net Interchanged	**(1,819,871)**	(1,529,643)	(2,576,167)	(4,428,059)	(4,627,627)	(1,864,214)	(1,738,833)	(1,268,780)	(1,148,903)	(2,716,242)
Net	**11,389,671**	11,325,746	11,231,545	11,442,454	10,636,356	10,612,818	10,535,827	10,073,047	10,031,905	9,518,802