Nebraska Public Power District
Always there when you need us

NLS2012063 140.21
July 3, 2012

Attention: Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Subject: Licensee Guarantees of Payment of Deferred Premiums
Cooper Nuclear Station, Docket No. 50-298, DPR-46

Dear Sir or Madam:

The purpose of this letter is to transmit information in accordance with the requirements of 10 CFR Part 140.21, relative to deferred insurance premiums, for the Nebraska Public Power District (NPPD). NPPD believes this information demonstrates our ability to obtain funds in the amount of $17.5 million for payment of such premiums within the specified three-month period.

To demonstrate the ability to provide funds in the required amount for such deferred insurance premiums, NPPD's 2011 Financial Report is enclosed for your review. This report is NPPD's audited financial statement. Please refer to Page 15 of the enclosure where the Balance Sheet of NPPD is listed. Cash and investments of NPPD total over $1 billion as indicated on Page 22, Note 3 of the enclosure. Liquidity can be provided by unrestricted cash and investments, and through reserve and special purpose funds that, with the approval of the NPPD Board of Directors, can be utilized for any lawful purpose. The portion of cash and investments that can be utilized to provide such liquidity for the payment of the subject deferred premiums is $346.5 million as of December 31, 2011.

Also on Page 15 of the enclosure, under the heading "Long-Term Debt," there is a line item titled "Commercial paper notes and revolving credit agreements" in the amount of $225.1 million. As noted on Page 28, Note 9 and Note 11 of the enclosure, NPPD is authorized to issue up to $150 million of tax-exempt commercial paper notes (TECP), $150 million of the Tax-Exempt Revolving Credit Agreement (TERCA), and $50 million of the Taxable Revolving Credit Agreement (TRCA). As of December 31, 2011, NPPD had $40.0 million remaining capacity in its TECP program, $41.0 million remaining capacity of TERCA, and $43.9 remaining capacity of TRCA, for a total of $124.9 million, which is available to fund the payment of the subject deferred premiums.

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NRR

It is NPPD's intent to continue to publish this report on an annual calendar year basis. A subsequent report, covering financial information for calendar year 2012, will be submitted no later than July 31, 2013.

This letter contains no new commitments.

Should you have questions, or require additional information, please contact me at (402) 825-2904.

Sincerely,

David W. Van Der Kamp
Licensing Manager

/jo

Enclosure: NPPD's 2011 Financial Report

cc: Regional Administrator w/enclosure
USNRC - Region IV

Cooper Project Manager w/enclosure
USNRC - NRR Project Directorate IV-1

Senior Resident Inspector w/o enclosure
USNRC - CNS

NPG Distribution w/o enclosure

D. K. Starzec w/o enclosure

D. M. Blatchford w/o enclosure

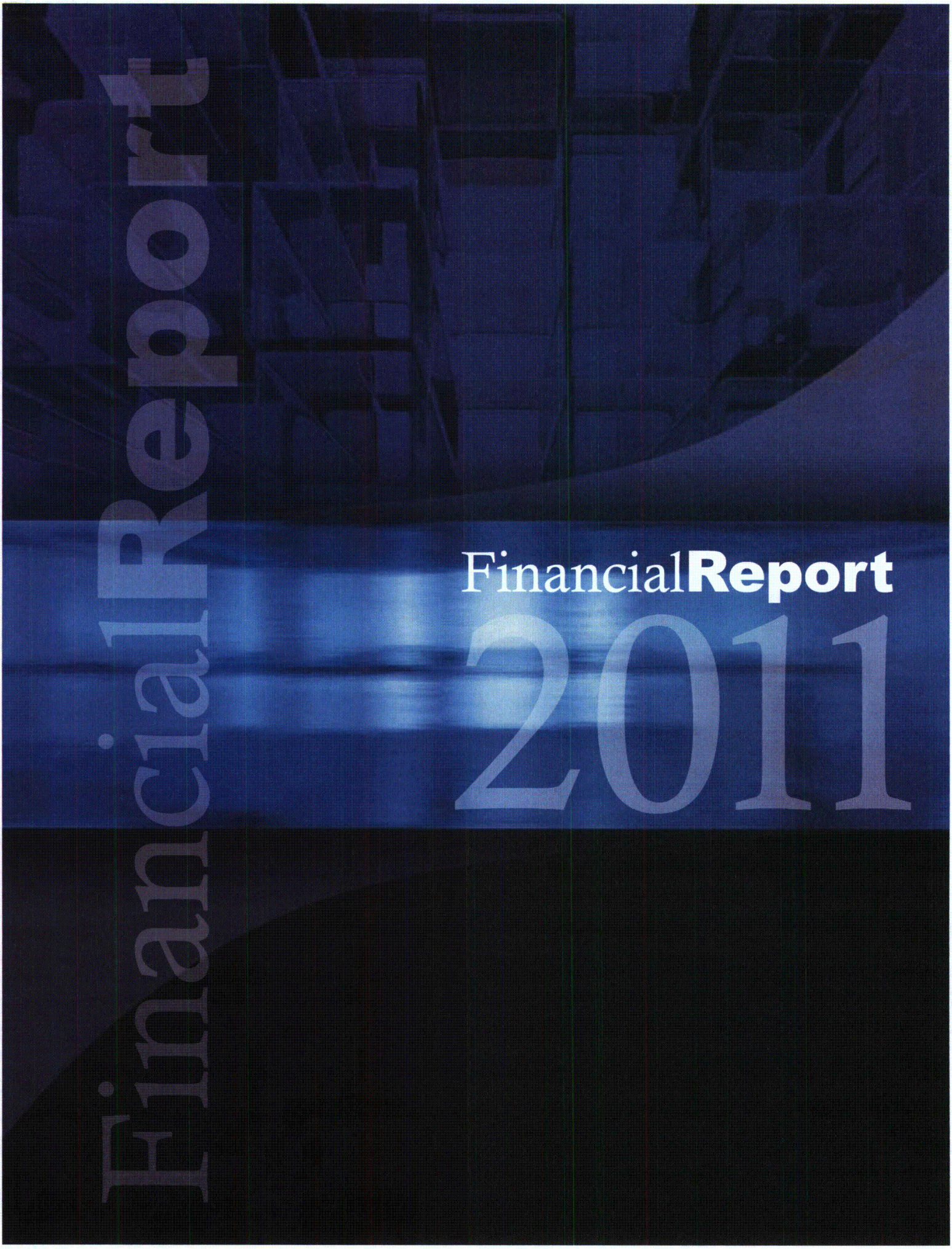
CNS Records w/enclosure

NLS2012063
Enclosure

ENCLOSURE

NEBRASKA PUBLIC POWER DISTRICT
2011 FINANCIAL REPORT

COOPER NUCLEAR STATION
DOCKET NO. 50-298, DPR-46


FinancialReport
FinancialReport
2011

2011 YEAR AT A GLANCE

KILOWATT-HOUR SALES	**19.9 BILLION**
OPERATING REVENUES	**998.7 MILLION**
COST OF POWER PURCHASED AND GENERATED	**582.3 MILLION**
OTHER OPERATING EXPENSES	**320.2 MILLION**
INCREASE IN FUND EQUITY	**45.7 MILLION**
DEBT SERVICE COVERAGE	**1.65**

2011 STATISTICAL REVIEW

SALES	Average Number of Customers	Electric Energy MWh Sales Amount	%	Revenues from Electric Sales (000's) Amount	%	Revenue Per kWh
Retail:						
Residential	68,587	842,349	4.2	$ 93,260	9.4	11.07¢
Rural and Farm	3,091	70,688	0.4	7,116	0.7	10.07¢
Commercial	15,002	916,423	4.6	82,144	8.2	8.96¢
Industrial	58	1,248,136	6.3	66,789	6.7	5.35¢
Public Lighting	194	18,942	0.1	2,872	0.3	15.16¢
Municipal Power	185	26,414	0.1	2,340	0.2	8.86¢
Miscellaneous Municipal	1,990	138,077	0.7	8,940	0.9	6.47¢
Total Retail Sales	89,107	3,261,029	16.4	263,461	26.4	8.08¢
Wholesale:						
52 Municipalities (Total Requirements)		1,996,992	10.1	112,347	11.2	5.63¢
25 Public Power Districts and Cooperatives (Total Requirements)		7,136,895	35.9	380,176	38.1	5.33¢
Total Wholesale Sales (Excluding Sales to LES and Other Utilities)		9,133,887	46.0	492,523	49.3	5.39¢
Total Retail and Wholesale Sales (Excluding Sales to LES and Other Utilities)		12,394,916	62.4	755,984	75.7	6.10¢
LES[1]		1,340,011	6.7	33,633	3.4	2.51¢
Other Utilities (Nonfirm and Other Sales)		6,134,250	30.9	183,759	18.4	3.00¢
Total Electric Energy Sales		19,869,177	100.0	973,376	97.5	4.90¢
Other Operating Revenues (Net of Deferred)				25,315	2.5	
Total Operating Revenues				$ 998,691	100.0	

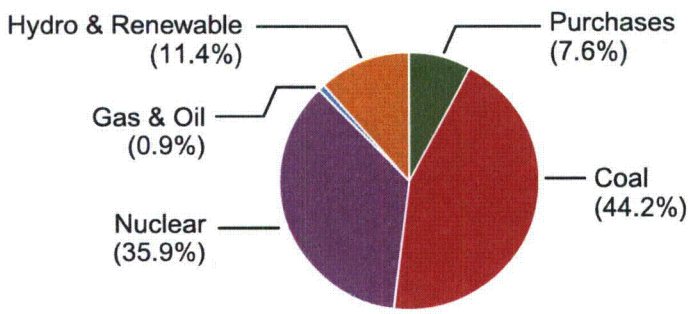
GENERATION	MWh Amount	%	Production Costs (000's) Amount	%
Production (Including Interchange)[2]	17,166,134	83.3	$ 451,175	77.5
Power Purchased	3,444,728	16.7	131,175	22.5
Total Power Produced and Purchased	20,610,862	100.0	$ 582,350	100.0

(1) Sales to Lincoln Electric System ("LES") include power and energy produced at Nebraska Public Power District's Gerald Gentleman Station and Sheldon Station.
(2) Costs include only fuel, operation, and maintenance costs. Debt service and capital related costs are excluded.

Miles of Transmission and Subtransmission Line in Service	5,132
Number of Employees (Filled Full-Time and Part-Time Positions)	2,173
2011 Contractual and Tax Payments (000's):	
Payments to Retail Communities	$ 24,332
Payments in Lieu of Taxes	$ 9,211

SOURCES OF ENERGY - 2011

For service to retail and to total requirements wholesale customers (excludes sales to Other Utilities and LES).



MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis should be read in conjunction with the audited Financial Statements and Notes to Financial Statements beginning on page 15.

OVERVIEW OF BUSINESS

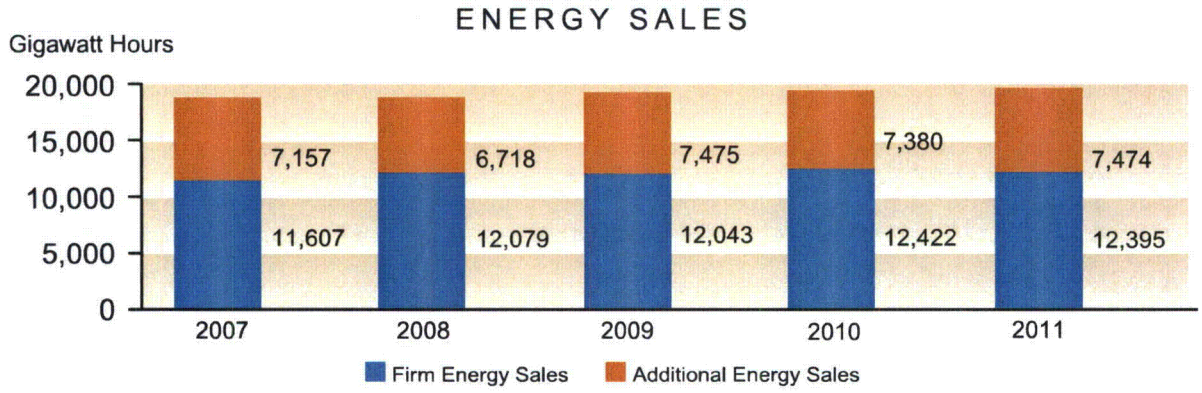
Nebraska Public Power District (the "District") operates an integrated electric utility system including facilities for generation, transmission, and distribution of electric power and energy for sales to wholesale and retail customers. The District is a summer peaking utility. An all-time system summer peak demand of 2,671 MW was established in July 2006 for the District's firm requirements customers. The District's all-time winter peak demand is 2,219 MW, which was established in December 2009. The District owns or has operating control over 35 generating plants, which had a combined accredited capacity during the summer of 2011 of 3,058.7 MW.

	GENERATION PLANTS		
Type:	Number of Plants[1]	Summer 2011 Accredited Capability (MW)	Percent of Total
Coal - Gerald Gentleman Station	1	1,365.0	44.6
Coal - Sheldon Station	1	225.0	7.4
Gas - Beatrice Power Station	1	217.0	7.1
Gas/Oil - Canaday Station	1	92.0	3.0
Nuclear - Cooper Nuclear Station	1	765.9	25.0
Hydro	9	165.6	5.4
Diesel	17	101.2	3.3
Combustion Turbine	3	127.0	4.2
Wind	1	0.0	0.0
	35	3,058.7	100.0

(1) Includes six hydro plants and 17 diesel plants under contract to the District.

In addition to the above generating plants, the District purchases 450.5 MW of firm power from the Western Area Power Administration and other capacity and energy on both a short-term and nonfirm basis in the wholesale energy market. The District had other capacity purchases of 162.0 MW from Omaha Public Power District's ("OPPD") Nebraska City Station Unit 2 ("NC2") coal-fired plant. Of the total capacity resources, 301.7 MW are being sold via participation sales or other capacity sales agreements. The District owns and operates 5,132 miles of transmission and subtransmission lines, encompassing the entire State of Nebraska.

The District's customer base for firm energy sales consists of approximately 89,110 retail customers plus 77 municipalities, public power districts, and cooperatives that are total requirements wholesale customers of the District. In addition, the District has several participation sale contracts in place with other utilities for the sale of power and energy at wholesale from specific generating plants. The District also sells energy on a nonfirm basis in the wholesale energy market.



CONDENSED BALANCE SHEETS

Condensed Balance Sheets (000's):	2011	2010	2009
Utility Plant, net	$ 2,402,025	$ 2,318,607	$ 2,235,069
Special Purpose Funds	790,264	882,484	767,497
Current Assets	567,237	442,806	383,128
Deferred Charges and Other Assets	706,816	695,211	811,805
Total Assets	$ 4,466,342	$ 4,339,108	$ 4,197,499
Fund Equity	$ 1,006,335	$ 960,598	$ 899,866
Long-Term Debt	2,056,810	1,943,728	2,009,021
Current Liabilities	270,795	426,394	206,642
Deferred Credits and Other Liabilities	1,132,402	1,008,388	1,081,970
Total Fund Equity and Liabilities	$ 4,466,342	$ 4,339,108	$ 4,197,499

CONDENSED RESULTS OF OPERATIONS

Condensed Statements of Revenues, Expenses, and Changes in Fund Equity (000's):	2011	2010	2009
Operating Revenues	$ 998,691	$ 925,141	$ 863,398
Operating Expenses	(902,523)	(808,864)	(796,904)
Operating Income	96,168	116,277	66,494
Investment and Other Income	42,622	32,768	31,860
Debt and Other Expenses	(93,053)	(88,313)	(82,164)
Increase in Fund Equity	$ 45,737	$ 60,732	$ 16,190

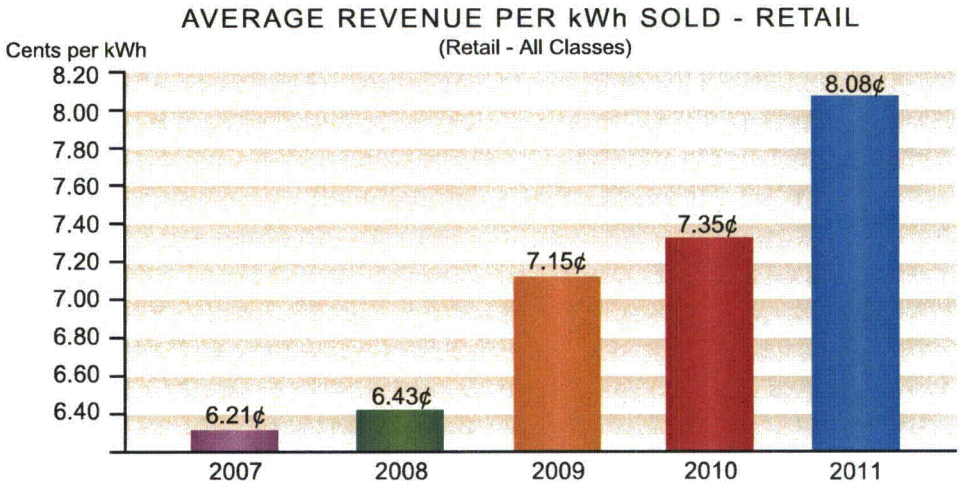
The sources of operating revenues were as follows (000's):

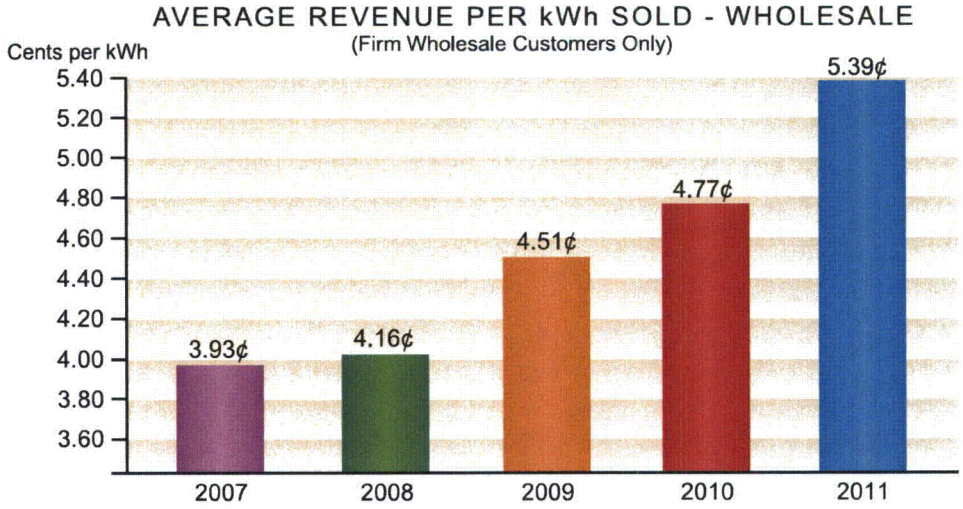
	2011	2010	2009
Firm Sales - Wholesale and Retail	$ 755,984	$ 676,499	$ 621,985
Participation Sales to LES and MEC[1]	33,633	35,186	77,307
Sales to Other Utilities	183,759	180,168	123,711
Other Operating Revenue	40,811	40,239	31,304
Deferred Revenue	(15,496)	(6,951)	9,091
Total Operating Revenue	$ 998,691	$ 925,141	$ 863,398

(1) The participation sales to MidAmerican Energy Company ("MEC") from Cooper Nuclear Station ("CNS") ended in December 2009.

Revenues from Firm Sales - Wholesale and Retail

Revenues from firm sales increased $79.5 million, or 11.8%, from $676.5 million in 2010 to $756.0 million in 2011. This increase is due primarily to 9.7% wholesale and 10.6% retail rate increases effective January 1, 2011, as a result of infrastructure investments, reduced energy prices in the nonfirm market, two plant maintenance outages in 2011, and increases in coal and nuclear fuel prices. Revenues from firm sales increased $54.5 million, or 8.8%, from $622.0 million in 2009 to $676.5 million in 2010. This increase is due primarily to 5.9% wholesale and 5.7% retail rate increases effective January 1, 2010, as a result of a $140.0 million investment in a high-voltage transmission line needed in eastern Nebraska and a $198.2 million investment in its shared costs of OPPD's NC2 power plant. An additional increase is due to a 3.1% increase in Kilowatt-hour energy sales.





Revenues from Participation Sales to LES and MEC and Sales to Other Utilities

During 2011, the District made participation sales to LES from the capacity and energy produced at Gerald Gentleman Station ("GGS") and Sheldon Station; to KCP&L Greater Missouri Operations Company ("KCPL") from GGS and CNS; to Heartland Consumers Power District ("Heartland") from CNS; and to the Municipal Energy Agency of Nebraska ("MEAN") from GGS and CNS. The District also engaged in sales of energy with other utilities on a nonfirm basis.

Revenue from participation sales to LES decreased from $35.2 million in 2010 to $33.6 million in 2011. The decrease is due primarily to LES's share of capital costs related to Sheldon Station being less in 2011 than in 2010. Revenue from participation sales to LES and MEC decreased from $77.3 million in 2009 to $35.2 million in 2010. The decrease is due primarily to the MEC power sales contract expiring at the end of 2009. This contract was not renewed.

Sales to other utilities consist of participation sales to KCPL, Heartland, and MEAN and nonfirm off-system sales. The Energy Authority ("TEA"), of which the District is a member, has energy marketing responsibilities for the District's nonfirm off-system sales and the related management of credit risks. Sales to other utilities increased from $180.2 million in 2010 to $183.8 million in 2011, an increase of $3.6 million. This increase is due primarily to additional revenue realized from nonfirm off-system sales as the result of excess generation being available to sell on the open market. Sales to other utilities increased from $123.7 million in 2009 to $180.2 million in 2010, an increase of $56.5 million. This increase is due primarily to additional revenue realized from nonfirm off-system sales as the result of excess generation being available to sell on the open market due to the expiration of the MEC power sales contract at the end of 2009 and no refueling outage in 2010 for CNS versus 2009.

Other Operating Revenue

Other operating revenue consists primarily of transmission wheeling revenues and revenue from work for other utilities. These revenues were $40.8 million, $40.2 million, and $31.3 million in 2011, 2010, and 2009, respectively. The increase in 2010 is due primarily to Southwest Power Pool ("SPP") Schedule 11 revenues which represent costs paid by other transmission owners of SPP to the District for its qualifying transmission upgrade projects.

Deferred Revenue

The District's wholesale and retail electric rates are established on a prospective basis. The estimated revenue requirements used to establish rates include operating expenses, excluding depreciation and amortization; debt service requirements on revenue bonds; payments of principal and interest on subordinated debt; amounts for capital projects to be paid from current revenues; amounts for reserves to pay future costs, such as future nuclear facility decommissioning costs; and other postretirement benefit costs, net of revenue received from LES and other utilities (nonfirm and other sales).

Under the provisions of the District's wholesale power contracts, if the rates for wholesale power service in any year result in a surplus or deficiency in revenues necessary to meet revenue requirements, such surplus or deficiency, within certain limits set forth in the wholesale power contracts, may be retained in a rate stabilization account. Any amounts in excess of the limits will be included as an adjustment to revenue requirements in future rate periods. A similar process is followed in accounting for any surplus or deficiency in revenues necessary to meet revenue requirements for retail electric service. Under generally accepted accounting principles for regulated electric utilities, such surpluses or deficiencies are accounted for as "regulatory assets or liabilities." The District follows this accounting treatment.

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

During 2011, revenues from electric sales to wholesale, retail, and other utilities exceeded actual revenue requirements. During 2010 and 2009, actual revenue requirements exceeded electric sales to wholesale, retail, and other utilities in each such year.

The District deferred or decreased revenues a net amount of $15.5 million in 2011. The District's revenues in 2011 from electric sales to wholesale, retail, and other utilities resulted in a surplus, or over collection of costs, of $15.5 million, which surplus amount was deferred (decrease in revenues).

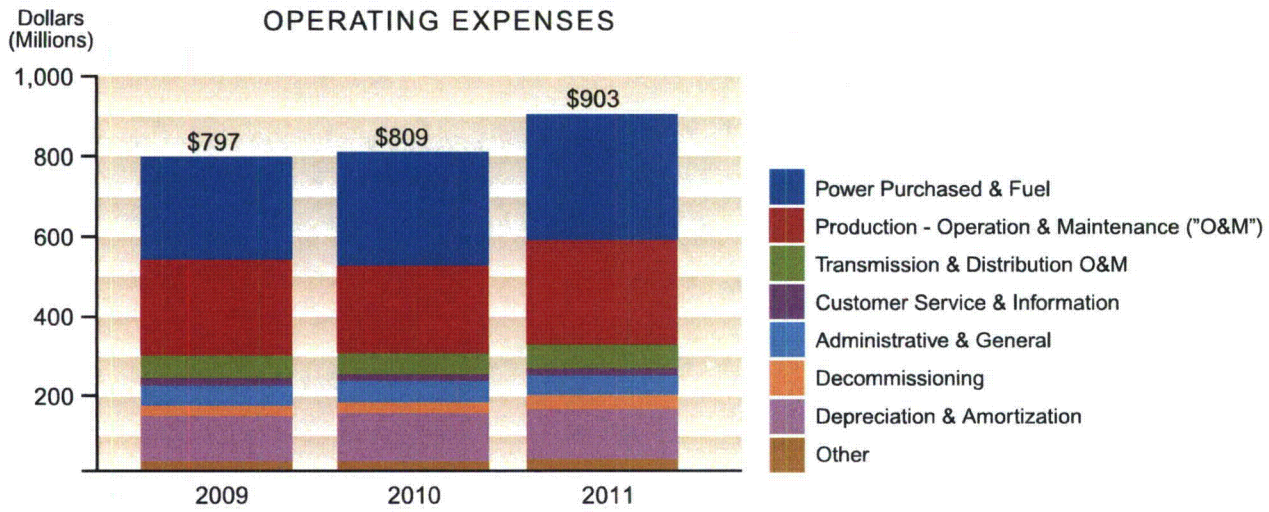
The District deferred or decreased revenues a net amount of $7.0 million in 2010. The District's revenues in 2010 from electric sales to wholesale, retail, and other utilities resulted in a deficiency, or under collection of costs, of $0.2 million, which deficiency amount was accrued (increase in revenues). In addition, the wholesale rates that were in place for 2010 included a collection of $7.2 million of deferred costs from past rate periods. Such deferral had previously been accounted for as an increase in revenue in the year(s) the deficiency occurred. Accordingly, the 2010 revenues from electric sales, which reflect the deferred costs being collected, are offset by a revenue adjustment (decrease in revenues) for such amount.

The District recognized or increased revenues a net amount of $9.1 million in 2009. The District's revenues in 2009 from electric sales to wholesale, retail, and other utilities resulted in a deficiency, or under collection of costs, of $4.3 million, which deficiency amount was accrued (increase in revenues). In addition, the wholesale and retail rates that were in place for 2009 included a refund of $4.8 million of surplus net revenues from past rate periods. Such surplus had previously been accounted for as a reduction in revenue in the year(s) the surplus occurred. Accordingly, the 2009 revenues from electric sales, which reflect the surplus being refunded, are offset by a revenue adjustment (increase in revenues) for such amount.

As of December 31, 2011, 2010, and 2009, the District had $66.3 million, $50.8 million, and $43.8 million, respectively, of surplus deferred revenues yet to be applied as credits against revenue requirements in future rate periods.

Operating Expenses

The following chart illustrates operating expenses for the years 2009, 2010, and 2011.



Total operating expenses in 2011 were $902.5 million, an increase of $93.7 million from 2010. Total operating expenses in 2010 were $808.9 million, an increase of $12.0 million from 2009. The changes were due primarily to the following:

Purchased power and production fuel expenses were $316.4 million, $286.4 million, and $259.0 million in 2011, 2010, and 2009, respectively. These expenses increased $30.0 million in 2011 as compared to 2010 due primarily to 11 months of purchases from Laredo Ridge Wind Facility which began commercial operation February 1, 2011, increased hydro purchases, increased wind purchases from Elkhorn Ridge Wind Facility, and higher fuel costs as a result of continued price increases in coal and related transportation costs. These expenses increased $27.4 million in 2010 as compared to 2009 due primarily to increased native load sales, a full year of purchases from NC2, increased hydro purchases, and higher fuel costs as a result of continued price increases in both coal and nuclear fuel and related transportation costs.

Production operation and maintenance expenses were $265.9 million, $220.3 million, and $246.3 million in 2011, 2010, and 2009, respectively. These costs increased $45.6 million in 2011 as compared to 2010 due primarily to the costs associated with a planned refueling and maintenance outage at CNS in 2011. No such outage occurred in 2010. These costs decreased $26.0 million in 2010 as compared to 2009 due primarily to the costs associated with a planned refueling and maintenance outage at CNS in 2009. No such outage occurred in 2010.

Transmission and distribution operation and maintenance expenses were $59.1 million, $54.3 million, and $55.7 million in 2011, 2010, and 2009, respectively. These costs increased $4.8 million in 2011 as compared to 2010 due primarily to increases in SPP wheeling and Schedule 11 fees. These expenses did not vary significantly from 2010 to 2009.

Customer service and information expenses were $19.6 million, $18.1 million, and $18.7 million in 2011, 2010, and 2009, respectively. These expenses did not vary significantly from year to year.

Administrative and general expenses were $51.1 million, $53.2 million, and $53.2 million in 2011, 2010, and 2009, respectively. These expenses did not vary significantly from year to year.

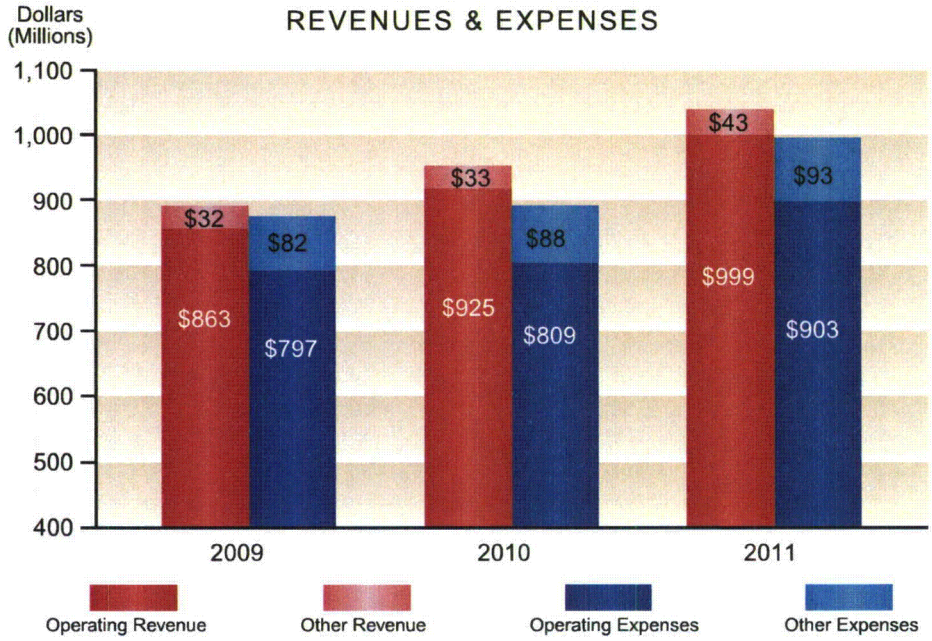
Decommissioning expenses were $33.8 million, $27.1 million, and $25.8 million in 2011, 2010, and 2009, respectively. Decommissioning expenses represent the net amount accrued each year for the future decommissioning of CNS. Such expenses are recorded in an amount equivalent to the interest income and market value changes of investments in the nuclear facility decommissioning fund plus amounts collected for decommissioning in the rates for electric service in such year. Decommissioning expenses increased by $6.7 million in 2011 as compared to 2010 due to an increase in market value changes of investments. Decommissioning expenses increased by $1.3 million in 2010 as compared to 2009 due to an increase in interest income on investments. No amount for decommissioning was collected through rates in 2009, 2010, or 2011.

To the extent that the accretion on the asset retirement obligation determined under Accounting Standards Codification 410 is different from the total of amounts collected in rates and investment earnings on monies accumulated in the decommissioning funds, the District will defer that difference as a regulatory asset or liability to be recovered or refunded in future periods. Accretion for 2011, 2010, and 2009 was $41.6 million, $44.8 million, and $46.2 million, respectively, and decommissioning expense was $33.8 million, $27.1 million, and $25.8 million, respectively.

Depreciation and amortization expenses were $123.1 million, $119.2 million, and $110.7 million in 2011, 2010, and 2009, respectively. These expenses increased $3.9 million in 2011 as compared to 2010 due primarily to recent investments at CNS and upgrades to the transmission infrastructure including various substations and lines. These expenses increased $8.5 million in 2010 as compared to 2009 due primarily to the depreciation of a new high-voltage transmission line in eastern Nebraska beginning in January 2010 and a full year of amortization of the NC2 prepaid power purchase and prepaid transmission costs.

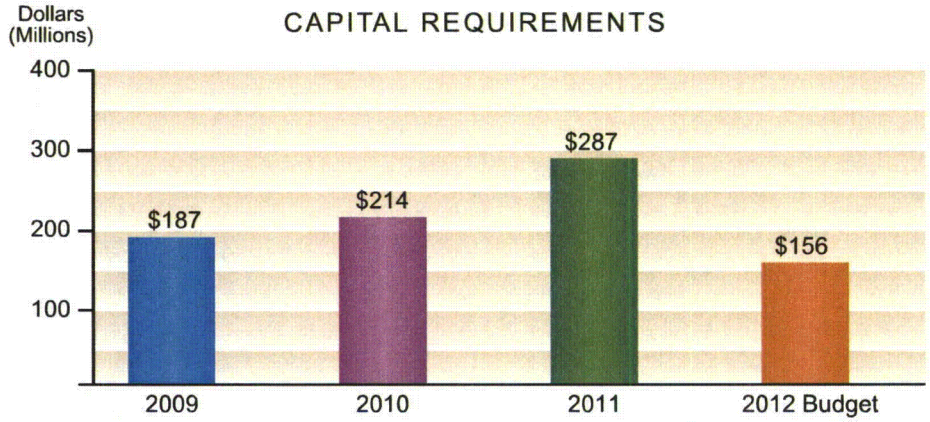
Increase in Fund Equity

The increase in fund equity (net revenues) was $45.7 million in 2011, $60.7 million in 2010, and $16.2 million in 2009. The decrease in fund equity of $15.0 million in 2011 as compared to 2010 reflects decreases in revenue requirements used to establish rates for construction from revenue along with an increase in depreciation expense partially offset by increased revenue bond principal payments. The increase in fund equity of $44.5 million in 2010 as compared to 2009 reflects increases in revenue requirements used to establish rates for 2010 for the purpose of increased revenue bond and commercial paper principal payments partially offset by increased depreciation expense and decreased interest income on construction funds.



CAPITAL REQUIREMENTS

The District's Board of Directors ("Board") authorized capital projects totaling approximately $287.1 million in 2011, $214.3 million in 2010, and $186.9 million in 2009. The amount for 2011 included $65.9 million for Phase II of construction of a high-voltage transmission line from Axtell, Nebraska to the Kansas border, $50.1 million for construction of transmission lines and substations related to the TransCanada Keystone XL Pipeline Project (this project has been put on hold as of December 31, 2011), the majority of which will be reimbursed by TransCanada, $39.3 million for installation of low nitrogen-oxide burners at GGS, and $9.2 million for Phase II of an electrical power back feed at CNS. The amount for 2010 included $32.6 million for construction of transmission lines and substations related to the South Sioux City Expansion Project, $27.7 million for the replacement of a high pressure turbine at CNS, $21.7 million for replacement of four main power transformers at CNS, and $11.0 million for Phase I costs related to the construction of a high-voltage transmission line from Axtell, Nebraska to the Kansas border. The amount for 2009 included an additional supplement of $19.3 million for a dry cask fuel storage facility at CNS, $17.2 million for the security facility modification at CNS, $16.1 million for replacement of four feedwater heaters at CNS, $12.8 million for Phase I of the installation of a statewide radio system, and $12.5 million for the first campaign to move spent nuclear fuel from the cooling pool to the storage pad. The remaining capital projects authorized in 2011, 2010, and 2009, which totaled $122.6 million, $121.3 million, and $109.0 million, respectively, were primarily for renewals and replacements to existing facilities and other minor additions and improvements. The District's Board-approved budget for capital projects for 2012 is $155.7 million, which includes $9.4 million for replacement of boiler waterwall tubes at GGS, $6.9 million for upgrade of reactor core instrumentation at CNS, and $6.0 million for a backup startup station service transformer at CNS. The District's capital requirements are funded by a combination of monies generated from operations, issuance of revenue bonds, issuance of short-term debt, and other available reserve funds.



FINANCING ACTIVITIES

The District had $1.954 billion (par amount) of outstanding revenue bonds at December 31, 2011, as compared to $2.014 billion (par amount) at December 31, 2010, and $1.843 billion (par amount) at December 31, 2009. The revenue bonds outstanding are at fixed interest rates and were issued at premiums or discounts. The District had outstanding $110.0 million of tax-exempt commercial paper ("TECP") notes at December 31, 2011, $122.0 million at December 31, 2010, and $117.0 million at December 31, 2009. Also, the District had outstanding $98.9 million of taxable commercial paper ("TCP") notes at December 31, 2010, and $117.2 million at December 31, 2009. The District is authorized to issue up to $150.0 million of TECP notes and have a bank credit agreement, expiring August 1, 2014, maintained to support the sale of the commercial paper notes. The District was authorized to issue up to $200.0 million of TCP notes and had a bank credit agreement which expired on August 1, 2011. This agreement was not renewed.

In 2011, the District established tax-exempt and taxable revolving credit agreements. The District had outstanding at December 31, 2011, $109.0 million under the tax-exempt revolving credit agreement ("TERCA") and $6.1 million under the taxable revolving credit agreement ("TRCA"). The District is authorized to borrow up to $150.0 million and $50.0 million on the TERCA and TRCA, respectively. Both the TERCA and TRCA have a bank credit agreement, expiring August 1, 2014 and November 30, 2014, respectively, maintained to support the lines of credit.

In May 2011, the District issued $61.4 million of tax-exempt revenue bonds to refund $64.2 million of TCP notes.

In September 2010, the District issued $114.1 million of taxable revenue bonds (Build America Bonds) and $147.1 million of tax-exempt revenue bonds to finance $164.8 million of the costs of certain generation, transmission, and distribution capital additions, to refund $77.6 million of TCP notes, and to refund $16.8 million of TECP notes. Also in September 2010, the District issued $8.4 million of taxable revenue bonds to refund $8.2 million of TCP notes.

In June 2009, the District issued $50.4 million of taxable revenue bonds (Build America Bonds) and $17.9 million of tax-exempt revenue bonds for certain generation and other transmission capital additions. Also in June 2009, the District issued $100.0 million of taxable revenue bonds to refund $69.5 million of TCP notes and to provide $28.4 million for certain capital additions at CNS.

The District retired $120.8 million, $99.0 million, and $81.2 million of General System Revenue Bonds in 2011, 2010, and 2009, respectively.

The District's current credit ratings on its long-term debt are as follows:

Moody's Investors Service	A1	(stable outlook)
Standard & Poor's Ratings Services	A	(stable outlook)
Fitch Ratings	A+	(stable outlook)

DEBT SERVICE COVERAGE

The District's debt service coverage was 1.65 in 2011, 1.73 in 2010, and 1.69 in 2009. The coverage is provided primarily by the amounts collected in operating revenues to fund the cost of utility plant additions, the amounts collected in operating revenues for principal and interest payments on the outstanding commercial paper notes, the amounts collected in operating revenues for principal associated with the 2008 Series A Bonds maturing January 1, 2014 and the 2009 Series B Bonds maturing January 1, 2013 and 2014, and the amounts collected in operating revenues to fund the cost of payments made to those municipalities served by the District under long-term Professional Retail Operating Agreements. The District has established a goal in its planning process to maintain a debt service coverage of approximately 1.5 times annual debt service.

CNS FUTURE OPERATION

Cooper Nuclear Station is currently licensed to operate until January 2034. On November 29, 2010, the Nuclear Regulatory Commission ("NRC") formally issued a certificate to the District to commemorate the renewal of the operating license for CNS for an additional 20 years until January 18, 2034. The issuance of this certificate by the NRC marked the culmination of the six-year effort to reach this milestone. The District is also evaluating the potential for an extended power uprate of CNS.

The District entered into an agreement for support services at CNS with Entergy Nuclear Nebraska, LLC ("Entergy"), a wholly-owned indirect subsidiary of Entergy Corporation, in October 2003. The Entergy agreement was for an initial term ending January 18, 2014. The agreement was subsequently extended, effective January 1, 2010, to January 18, 2029. The agreement requires the District to reimburse Entergy's costs of providing services and to pay Entergy annual management fees. Since 2007, Entergy has been eligible to earn additional incentive fees if CNS achieves identified safety and regulatory performance targets during each such year.

The District entered into a power sales contract with MEC to provide 250 MW of capacity and energy from January 1, 2005 through December 31, 2009. This contract was not renewed. The District also entered into agreements for the sale of capacity and energy from CNS to Heartland, to KCPL, and to MEAN. The Heartland agreement provides for delivery of capacity and energy from January 1, 2004 through December 31, 2013, in amounts ranging from 5 MW up to 45 MW. The KCPL agreement provides for delivery of 75 MW of capacity and energy from January 1, 2005 through January 18, 2014. The MEAN agreement, amended on December 27, 2010, provided for delivery of capacity and energy from July 1, 2008 through December 31, 2010, of 95 MW, of which 60% was provided from CNS and 40% from GGS. In addition, the amended agreement provided for delivery of capacity and energy from January 1, 2011 through the last day of the month prior to the commercial operation of the Whelan Energy Center 2, a 220 MW coal-fired power plant, of 45 MW, of which 29 MW was provided from CNS and 16 MW from GGS. MEAN has an ownership interest in WEC2, which began commercial operation on May 1, 2011, and such agreement terminated on April 30, 2011. On December 27, 2010, the District entered into a second MEAN agreement for the delivery of capacity and energy from January 1, 2011 through December 31, 2023, of 50 MW, of which 26 MW will be provided from CNS and 24 MW from GGS.

As a result of the failure of the Department of Energy ("DOE") to dispose of spent nuclear fuel from CNS as required by contract, the District commenced legal action against the DOE on March 2, 2001. On March 17, 2011, the District offered to settle its litigation against the DOE for spent nuclear fuel disposal damages in exchange for the payment of $60.6 million representing costs incurred for the on-site storage of spent nuclear fuel at CNS through December 31, 2009, along with subsequent claims pursuant to the provisions of the settlement agreement. On June 17, 2011, in accordance with the settlement agreement between the District and the DOE, the District received $60.6 million from the DOE for damages through 2009. The District received a second payment from the DOE in the amount of $10.3 million on October 21, 2011 for its subsequent claim submittal to recover the District's costs incurred in 2010. The settlement agreement addresses future claims through 2013. The District plans to use the funds to pay for future costs related to CNS.

RESOURCE PLANNING

The District increased its base load resources when OPPD's NC2 coal-fired plant began commercial operation on May 1, 2009. The District's share of this facility is 162 MW. With this addition to its already diverse power resource mix, and with various capacity and energy contracts between 2009 and 2014, the District is well positioned to meet its firm load requirement needs for the next 15 to 20 years. The District also continues to focus on the (i) addition of renewables, (ii) effectiveness of energy efficiency programs, (iii) evaluation of additional peaking capacity, and (iv) evaluation of an extended power uprate of CNS.

In July 2011, the District's Board approved a new Strategic Plan. As a result, several core initiatives have been started to further develop and make tactical recommendations to the Board regarding strategic goals. One of these initiatives is the Generation Options Analysis ("GOA"). The objective of the GOA is to develop a quantitative probabilistic model that can be used to support options for a recommendation to the Board regarding future operation of and additional investment in the District's coal-fired generating stations, and an extended power uprate at CNS. The GOA is expected to be completed by the first half of 2012, after which the District will complete an update to its Integrated Resource Plan in 2012. Preliminary results of the GOA, which are subject to further analysis, indicate that it may be more cost effective to retrofit GGS with full multi-pollutant control equipment than to cease operations and that CNS extended power uprate may be beneficial.

In December 2011, the District entered into a 25-year power purchase agreement with Broken Bow Wind II, LLC to purchase electric power from the 75 MW Broken Bow Wind II Facility planned for development near Broken Bow, Nebraska. Construction of this facility has commenced and is scheduled to begin commercial operation in December 2012. The District has entered into an agreement to sell 45 MW of the capacity of this project to another utility in Nebraska.

In February 2010, the District entered into a 20-year power purchase agreement with Laredo Ridge Wind, LLC to purchase electric power from the 80 MW Laredo Ridge Wind Facility near Petersburg, Nebraska, which began commercial operation on February 1, 2011. The District has entered into agreements to sell 19 MW of the capacity of this project to other utilities in Nebraska. In September 2010, the District entered into a 20-year power purchase agreement with Broken Bow Wind, LLC to purchase electric power from the 80 MW Broken Bow Wind Facility planned for development near Broken Bow, Nebraska. Construction of this facility has commenced and is scheduled to begin commercial operation in December 2012. The District plans to sell 37 MW of the capacity of this project to other utilities in Nebraska. In October 2010, the District entered into a 20-year power purchase agreement with Bluestem, LLC to purchase electric power from a 3 MW wind facility developed near Springview, Nebraska, which began commercial operation on October 1, 2011. The District has agreements to share the cost of this project with other utilities in Nebraska and will share the knowledge gained from the operation of these direct drive wind turbines.

In February 2008, the District entered into a 20-year power purchase agreement with Elkhorn Ridge Wind, LLC to purchase electric power from the 80 MW Elkhorn Ridge Wind Facility developed near Bloomfield, Nebraska, which began commercial operation on March 1, 2009. The District has entered into agreements to sell one-half of the capacity of this project to other utilities in Nebraska. In April 2008, the District entered into a 20-year power purchase agreement with Community Wind Energy Transmission, LLC to purchase electric power from the 42 MW Crofton Hills Wind Facility near Crofton, Nebraska. In 2011, Edison Mission Energy acquired the project and re-named it Crofton Bluffs Wind Facility resulting in a restated and amended agreement. The facility is planned for development in late 2012. The District plans to sell one-half of the capacity of this project to other utilities in Nebraska.

The District will pay only for energy delivered pursuant to such power purchase wind agreements and the cost of the substation and transmission work to connect these projects to the District's electric system. Participating utilities will pay their pro rata share of energy delivered and capital additions.

ENERGY RISK MANAGEMENT PRACTICES

The nature of the District's business exposes it to a variety of risks, including exposure to volatility in electric energy and fuel prices, uncertainty in load and resource availability, the creditworthiness of its counterparties, and the operational risks associated with transacting in the wholesale energy markets.

To help manage energy risks, the District relies upon TEA to both transact on its behalf in the wholesale energy markets and to develop and recommend strategies to manage the District's exposure to risks in the wholesale energy markets. TEA combines a strong knowledge of the District's system, an in-depth understanding of the wholesale energy markets, experienced people, and state-of-the-art technology to deliver a broad range of standardized and customized energy products and services to the District.

TEA has assisted the District in developing its Energy Risk Management ("ERM") program and associated ERM Governing Policy ("Policy"). The Policy, approved by the Board, establishes guidelines and objectives and delegation of authorities necessary to govern activities related to the District's ERM program. The objective of the ERM program is to increase fuel and energy price stability by hedging the risk of significant adverse impacts to cash flow. These adverse impacts could be caused by events such as natural gas or power price spikes or extended unplanned outages. The ERM program has been developed to provide assurance to the Board that the risks inherent in the wholesale energy market are being quantified and appropriately managed.

On April 1, 2009, the District became a member of SPP, a regional transmission organization based in Little Rock, Arkansas. Membership in SPP provides the District reliability coordination service, generation reserve sharing, regional tariff administration, including generation interconnection service, network, and point-to-point transmission service, and regional transmission expansion planning. The District is able to participate in SPP's energy imbalance market, a real-time balancing market that provides members the opportunity to have SPP dispatch resources based on marginal cost.

ECONOMIC FACTORS

The national economic slowdown and subsequent weak recovery have not had a significant impact on the District's native load electrical demand. The Midwest region has experienced unemployment rates that have been higher than pre-recession levels, but remain far below the national averages. The strong overall performance of Nebraska's agricultural sector, as measured by net farm income, has contributed to the state's positive economic performance. Nebraska's unemployment rate decreased from an average of 4.7% for 2010 to an average of 4.4% for 2011, compared to the national average unemployment rate of 9.6%. Nebraska's seasonally adjusted unemployment rate was 4.2% in December 2011 and 4.3% in December 2010, compared to the national seasonally adjusted unemployment rate of 8.5% and 9.4% in 2011 and 2010, respectively. For December 2011, the unemployment rate in Nebraska was the second lowest in the nation. The District continues to monitor changes in national and global economic conditions, as these could impact cost of debt and access to capital markets.

The District has not seen a significant increase in its uncollectible customer accounts.

COMMITMENTS AND CONTINGENCIES

The District entered into a Transmission Facilities Construction Agreement effective June 15, 2009, with TransCanada Keystone Pipeline, LP ("Keystone"). This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of Keystone to the District's transmission system. Cost of the project was $8.4 million and repayment by Keystone, over a ten-year period, began in July 2010 with a remaining balance due the District of $7.6 million as of December 31, 2011.

The District entered into a second Transmission Facilities Construction Agreement effective July 17, 2009, with TransCanada Keystone XL Pipeline, LP ("Keystone XL"). This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of Keystone XL to the District's transmission system. The initial estimated cost of

the project was $52.9 million and was to be paid by Keystone XL over a ten-year period anticipated to begin July 2013. However, the project was recently delayed due to routing concerns of the pipeline across the Nebraska Sandhills. Adjustments to the facilities, project costs, and completion schedules will be made once the final route is determined, which is anticipated in the fourth quarter of 2012. Keystone XL remains responsible for all present and future project costs. As of December 31, 2011, actual project costs totaled $7.6 million.

In connection with an examination by the Internal Revenue Service (the "Service") of the District's General Revenue Bonds, 2009 Series A (Taxable Build America Bonds), representatives of the Service verbally expressed the view to the District on February 1, 2012, that approximately $10.0 million principal amount of the bonds maturing on January 1, 2035, may not qualify for the 35% interest subsidy provided by the United States Treasury based on the interpretation by the Service of the issue price of the bonds to the public. The District does not agree with the Service's position and may contest any formal action taken by the Service. It is estimated that the 35% interest subsidy on the $10.0 million of bonds is approximately $260,000 per year. Any loss of such subsidy could be retroactive to the date of issuance of the bonds (June 24, 2009) and could total approximately $6.5 million over the stated term of the bonds.

SUBSEQUENT EVENT

In February 2012, the District issued $212.4 million of tax-exempt revenue bonds at a net premium to advance refund $167.2 million of bonds, to finance $40.3 million of the costs of certain generation and transmission capital additions, and to refund $20.2 million of the TERCA indebtedness. The refunded bonds represent a portion of the bonds issued in 2003 with maturities from January 1, 2015 through January 1, 2035. The refunding will result in debt service savings to the District of $27.1 million during the period February 2012 through December 2034.

REPORT OF INDEPENDENT AUDITORS

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

We have audited the accompanying balance sheets of Nebraska Public Power District (the "District") as of December 31, 2011 and 2010, and the related statements of revenues, expenses, and changes in fund equity and of cash flows for the years then ended. These financial statements are the responsibility of the District's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the District at December 31, 2011 and 2010, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Management's discussion and analysis included on pages two through thirteen is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted primarily of inquires of management, regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

In accordance with *Governmental Auditing Standards*, we have also issued our report dated April 12, 2012 on our consideration of the District's internal control over financial reporting and on our test of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters for the year ended December 31, 2011. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Governmental Auditing Standards* and should be considered in assessing the results of our audits.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental schedule, "Calculation of Debt Service Ratios in accordance with the General Revenue Bond Resolution for the years ended December 31, 2011 and 2010," is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

St. Louis, Missouri
April 12, 2012

FINANCIAL STATEMENTS

Balance Sheets - December 31, 2011 and 2010 (000's)	2011	2010
ASSETS		
Utility Plant, at Cost:		
Utility plant in service	$ 4,259,172	$ 4,128,177
Less reserve for depreciation	2,267,763	2,182,254
	1,991,409	1,945,923
Construction work in progress	204,099	183,949
Nuclear fuel, at amortized cost	206,517	188,735
	2,402,025	2,318,607
Special Purpose Funds:		
Cash and cash equivalents:		
Construction funds	23,870	—
Debt reserve fund	50	17
Employee benefit funds	4,696	2,433
Investments:		
Construction funds	135,245	286,997
Debt reserve fund	103,756	101,925
Employee benefit funds	4,697	6,982
Decommissioning funds	517,950	484,130
	790,264	882,484
Current Assets:		
Cash and cash equivalents	204,949	113,213
Investments	88,917	63,260
Receivables, less allowance for doubtful accounts of $528 and $531, respectively	87,474	84,682
Fossil fuels, at average cost	42,418	41,045
Materials and supplies, at average cost	125,383	122,593
Prepayments and other current assets	18,096	18,013
	567,237	442,806
Deferred Charges and Other Assets:		
Deferred asset retirement obligation	366,202	358,047
Deferred OPEB obligation	93,161	80,244
Long-term capacity contracts	200,407	210,990
Deferred settlement charges	5,223	10,199
Unamortized financing costs	14,287	15,860
Investment in The Energy Authority	8,755	7,614
Other	18,781	12,257
	706,816	695,211
TOTAL ASSETS	$ 4,466,342	$ 4,339,108
FUND EQUITY AND LIABILITIES		
Fund Equity:		
Invested in capital assets, net of related debt	$ 589,757	$ 591,565
Restricted	51,142	50,235
Unrestricted	365,436	318,798
	1,006,335	960,598
Long-Term Debt:		
Revenue bonds, net	1,831,710	1,943,728
Commercial paper notes and revolving credit agreements	225,100	—
	2,056,810	1,943,728
Current Liabilities:		
Current maturities of revenue bonds	161,565	111,145
Current maturities of commercial paper notes	—	220,872
Accounts payable and accrued liabilities	67,114	59,660
Accrued in lieu of tax payments	9,166	8,276
Accrued payments to retail communities	5,421	4,898
Accrued compensated absences	15,832	15,760
Other	11,697	5,783
	270,795	426,394
Deferred Credits and Other Liabilities:		
Asset retirement obligation	885,530	843,741
Deferred revenues	66,268	50,772
Other postemployment benefits	93,161	80,244
Other	87,443	33,631
	1,132,402	1,008,388
TOTAL FUND EQUITY AND LIABILITIES	$ 4,466,342	$ 4,339,108

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

Statements of Revenues, Expenses, and Changes in Fund Equity
for the years ended December 31, (000's)

	2011	2010
Operating Revenues	$ 998,691	$ 925,141
Operating Expenses:		
Power purchased	131,175	111,364
Production -		
Fuel	185,256	175,017
Operation and maintenance	265,919	220,348
Transmission and distribution operation and maintenance	59,091	54,296
Customer service and information	19,608	18,058
Administrative and general	51,052	53,220
Payments to retail communities	24,332	21,970
Decommissioning	33,819	27,107
Depreciation and amortization	123,060	119,151
Payments in lieu of taxes	9,211	8,333
	902,523	808,864
Operating Income	96,168	116,277
Non-Operating Income:		
Investment income	39,087	30,848
Other income	3,535	1,920
	42,622	32,768
Increase in Fund Equity Before Debt and Other Expenses	138,790	149,045
Non-Operating Expenses:		
Interest on long-term debt	100,146	93,061
Allowance for funds used during construction	(3,651)	(3,406)
Bond premium amortization net of debt issuance expense	(4,157)	(2,170)
Other expenses	715	828
	93,053	88,313
Increase in Fund Equity	45,737	60,732
Fund Equity:		
Beginning balance	960,598	899,866
Ending balance	$ 1,006,335	$ 960,598

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

Statements of Cash Flows for the years ended December 31, (000's)	2011	2010
Cash Flows from Operating Activities:		
Receipts from customers and others	$ 1,008,085	$ 939,741
Receipts from FEMA, State of Nebraska, and others	82,605	1,610
Payments to suppliers and vendors	(476,284)	(414,877)
Payments to employees	(238,258)	(231,539)
Net cash provided by operating activities	376,148	294,935
Cash Flows from Investing Activities:		
Proceeds from sales and maturities of investments	737,972	997,065
Purchase of investments	(609,983)	(1,048,540)
Income received on investments	4,931	6,032
Net cash provided by (used in) investing activities	132,920	(45,443)
Cash Flows from Capital and Related Financing Activities:		
Proceeds from issuance of bonds	64,922	283,636
Proceeds from issuance of notes	23,524	93,451
Proceeds from advance on tax-exempt and taxable revolving credit agreements	115,100	—
Proceeds from repayment of notes receivable	10	72
Capital expenditures for utility plant	(242,260)	(251,429)
Refurbishment at Kingsley Hydro	—	(3,086)
Principal payments on long-term debt	(120,790)	(99,000)
Interest payments on long-term debt	(100,146)	(93,061)
Principal payments on notes	(134,547)	(107,265)
Interest payments on notes	(305)	(446)
Funds advanced - Whelan Energy Center 2	(210)	—
Other non-operating revenues	3,536	1,920
Net cash used in capital and related financing activities	(391,166)	(175,208)
Net increase in cash and cash equivalents	117,902	74,284
Cash and cash equivalents, beginning of year	115,663	41,379
Cash and cash equivalents, end of year	$ 233,565	$ 115,663
Reconciliation of Operating Income to Cash Provided By Operating Activities:		
Operating income	$ 96,168	$ 116,277
Adjustments to reconcile operating income to net cash provided (used) by operating activities:		
Depreciation and amortization	123,060	119,151
Undistributed net revenue - The Energy Authority	(1,141)	(838)
Decommissioning, net of customer contributions	33,819	27,107
Amortization of nuclear fuel	46,462	49,667
Changes in assets and liabilities which (used) provided cash:		
Receivables, net	(1,376)	1,934
Fossil fuels	(1,373)	(9,731)
Materials and supplies	(2,790)	(5,473)
Prepayments and other current assets	288	(36)
Deferred charges	698	(129)
Accounts payable and accrued payments to retail communities	6,591	(10,733)
Deferred revenues	15,496	6,952
Other liabilities	60,246	787
Net cash provided by operating activities	$ 376,148	$ 294,935
Supplementary non-cash capital activities:		
Utility plant additions in accounts payable	$ 1,386	$ (5,752)

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

Supplemental Schedule - Calculation of Debt Service Ratios in accordance with the General Revenue Bond Resolution for the years ended December 31, (000's)	2011	2010
Operating revenues	$ 998,691	$ 925,141
Operating expenses	(902,523)	(808,864)
Operating income	96,168	116,277
Investment and other income	42,622	32,768
Debt and other expenses	(93,053)	(88,313)
Increase in fund equity	45,737	60,732
Add:		
Collections for future debt retirement	24,563	34,981
Debt and related expenses	93,053	88,313
Depreciation and amortization	123,060	119,151
Payments to retail communities[1]	24,332	21,970
Amortization of current portion of financed nuclear fuel	16,160	1,280
Amounts collected from third party financing arrangements[2]	697	113
	281,865	265,808
Deduct:		
Investment income retained in construction funds	671	1,453
Unrealized gain (loss) on investment securities	1,416	(1,151)
Revolving credit agreement interest	293	—
	2,380	302
Fund equity available for debt service under the General Revenue Bond Resolution	$ 325,222	$ 326,238
Amounts deposited in the General System Debt Service Account:		
Principal	$ 120,790	$ 99,000
Interest	75,818	89,193
	$ 196,608	$ 188,193
Ratio of fund equity available for debt service to debt service deposits	1.65	1.73

(1) Under the provisions of the General Revenue Bond Resolution, the payments required to be made by the District with respect to the Professional Retail Operating Agreements are to be made on the same basis as subordinated debt.

(2) Under the provisions of the General Revenue Bond Resolution, the payments received by the District from third party financing arrangements provide for debt service coverage, but are not recognized as revenue under Generally Accepted Accounting Principles.

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

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

A. Organization -

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

B. Basis of Accounting -

The financial statements are prepared in accordance with Generally Accepted Accounting Principles ("GAAP") and follow accounting guidance provided by the Governmental Accounting Standards Board ("GASB") codification. The District elected the option permitted by GASB Codification Section ("Cod. Sec.") P80, *Proprietary Fund Accounting & Financial Reporting* to implement all Accounting Standards Codification ("ASC") that do not conflict or contradict GASB pronouncements.

The District follows the provisions of ASC Section 980, *Regulated Operations* ("ASC 980"). In general, ASC 980 permits an entity with cost-based rates to defer certain costs or income that would otherwise be recognized when incurred to the extent that the rate-regulated entity is recovering or expects to recover such amounts in rates charged to its customers.

C. 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.

D. Revenue -

Wholesale revenues are recorded in the period in which service is rendered, and retail revenues are recorded in the month retail customers are billed. Consequently, revenues applicable to service rendered to retail customers from the period covered by the last billing in a year to the end of the year are not recorded as revenues until the following year.

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

The surpluses and deficits from prior years have been accounted for in these financial statements by either a deferral of revenue or costs. During the years ended December 31, 2011 and 2010, the District deferred net revenues of $15.5 million and $7.0 million, respectively. The cumulative surplus at December 31, 2011, to be reflected in future revenue requirements, is approximately $66.3 million.

E. Depreciation, Amortization, and Maintenance -

The District records depreciation over the estimated useful life of the property primarily on a straight-line basis. The District's electric rates are established based upon debt service and operating fund requirements. Straight-line depreciation is not considered in the design of rates. As such, the District has provided for depreciation of utility plant funded from debt in its rate setting process by using the debt service principal requirements as the basis for depreciation as opposed to the straight-line basis of depreciation included in the financial statements of the District. Under the methodology employed in establishing rates, the excess of

accumulated depreciation expense calculated using the debt service principal approach over the amount calculated using the straight-line method is $84.3 million and $55.3 million for the years ended December 31, 2011 and 2010, respectively. Annual depreciation expense calculated under the debt service principal approach exceeded straight-line depreciation by $15.3 million and $13.2 million for the years ended December 31, 2011 and 2010, respectively. Depreciation expense recorded on a straight-line basis on utility plant was $98.4 million and $94.2 million for the years ended December 31, 2011 and 2010, respectively. Depreciation on utility plant was approximately 2.5% in each of the years ended December 31, 2011 and 2010, respectively. The District has fully depreciated utility plant that is still in service of $826.9 million and $782.3 million at December 31, 2011 and 2010, respectively, primarily relating to Cooper Nuclear Station ("CNS").

Current rates for electric service provide for a portion of plant additions to be funded from revenues. These plant additions are capitalized and depreciated over their estimated useful life. At December 31, 2011 and 2010, $540.7 million and $532.0 million, respectively, of net utility plant was funded from revenues. Provision for depreciation of utility plant funded from revenues is computed using the straight-line method.

The District owns and operates the electric distribution system in one of the 80 municipalities that it serves at retail. In addition, the District has long-term Professional Retail Operating ("PRO") Agreements with 79 municipalities for certain retail electric distribution systems. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal property additions during the term of the agreements. The District has recorded provisions, net of retirements, for amortization of these plant additions of $9.2 million in 2011 and $9.9 million in 2010 which is included in depreciation and amortization expense. These plant additions, which are fully depreciated, totaled $160.6 million at December 31, 2011, and $153.1 million at December 31, 2010.

The District charges maintenance and repairs, including the cost of renewals and replacements of minor items of property, to maintenance expense accounts when incurred. Renewals and replacements of property (exclusive of minor items of property, as set forth above) are charged to utility plant accounts. Upon retirement of property subject to depreciation, the cost of property is removed from the plant accounts and charged to the reserve for depreciation, net of salvage.

F. Cash and Cash Equivalents -

The District considers highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

G. Fossil Fuel and Materials and Supplies -

The District maintains inventories for fossil fuels, and materials and supplies which are valued at average cost. Due provision is made for slow moving or obsolete items.

H. Nuclear Fuel -

The District had entered into a contract with General Electric for fuel bundle fabrication and related services. This contract was assigned effective January 2000 by General Electric to Global Nuclear Fuels-Americas. The contract, as amended, provides for these services through 2017. The District amended its existing contract with United States Enrichment Corporation extending it through 2013 for various nuclear fuel components including enrichment services. The District has purchased uranium hexafluoride on the spot market for inventory and will pursue additional spot and term contracts for such components as needed. Nuclear fuel in the reactor is being amortized on the basis of energy produced as a percentage of total energy expected to be produced. Fees for disposal of fuel in the reactor are being expensed as part of the fuel cost.

In December 2009, CNS completed construction of a dry cask used fuel storage facility to support planned license renewal. This facility was primarily funded from decommissioning funds and, as such, the value of the assets in Utility plant in service represents only the amounts that were not funded from decommissioning funds.

I. Unamortized Financing Costs -

These costs represent issuance expenses on all bonds and are being amortized over the life of the respective bonds using the bonds outstanding method. Deferred unamortized financing costs associated with bonds refunded are amortized using the bonds outstanding method over the shorter of the original or refunded life of the respective bonds in accordance with GASB Cod. Sec. D20, *Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities.*

J. Allowance for Funds Used During Construction ("AFUDC") -

This allowance, which represents the cost of funds used to finance construction, is capitalized as a component of the cost of the utility plant and is credited to Non-Operating Expenses. The capitalization rate depends on the source of financing. The rate for construction financed with revenue bonds is based upon the interest cost of each bond issue less interest income. Construction financed on a short-term basis with taxable commercial paper ("TCP"), tax-exempt commercial paper ("TECP"), tax-exempt revolving credit agreement ("TERCA"), or taxable revolving credit agreement ("TRCA") is charged a rate based upon the projected average interest cost of TCP, TECP, TERCA, or TRCA outstanding. For the periods presented herein, the AFUDC rates for construction funded by revenue bonds vary from 2.8% to 5.0%. For construction financed on a short-term basis with commercial paper, the rates charged vary from 1.3% to 1.5%.

K. Fund Equity -

Fund equity is made up of three components: Invested in capital assets, net of related debt, Restricted, and Unrestricted.

Invested in capital assets, net of related debt consists of utility plant assets, net of accumulated depreciation and reduced by the outstanding balances of any bonds or notes that are attributable to the acquisition, construction, or improvement of these assets. This component also includes long-term capacity contracts net of the outstanding balances of any bonds or notes attributable to these assets.

Restricted fund equity consists of the debt service reserve-primary funds that are required deposits under the Resolution and the Decommissioning funds net of any related liabilities.

Unrestricted fund equity consists of any remaining fund equity that does not meet the definition of Invested in capital assets, net of related debt or Restricted, and are used to provide for working capital to fund non-nuclear fuel and inventory requirements, as well as other operating needs of the District.

L. Asset Retirement Obligations -

Asset retirement obligations represent the fair value of the District's legal liability associated with the retirement of CNS, various ash landfills at its two coal-fired power stations, and the removal of asbestos at its various generating facilities.

M. Reclassifications -

Certain amounts in the prior year's financial statements have been reclassified to conform to the 2011 presentation. These reclassifications had no effect on Increase in Fund Equity or Total Fund Equity.

2. UTILITY PLANT:

Utility plant activity for the year ended December 31, 2011, was as follows (000's):

	December 31, 2010	Increases	Decreases	December 31, 2011
Nondepreciable utility plant:				
Land and improvements	$ 53,475	$ 260	$ (8)	$ 53,727
Construction in progress	183,949	175,360	(155,210)	204,099
Total nondepreciable utility plant	237,424	175,620	(155,218)	257,826
Nuclear fuel*	188,735	64,244	(46,462)	206,517
Depreciable utility plant:				
Generation - Fossil	1,481,196	18,532	(10,640)	1,489,088
Generation - Nuclear	1,147,025	61,955	(583)	1,208,397
Transmission	951,956	46,068	(4,846)	993,178
Distribution	191,196	10,048	(1,827)	199,417
General	303,329	14,616	(2,580)	315,365
Total depreciable utility plant	4,074,702	151,219	(20,476)	4,205,445
Less reserve for depreciation	(2,182,254)	(105,985)	20,476	(2,267,763)
Depreciable utility plant, net	1,892,448	45,234	—	1,937,682
Utility plant activity, net	$ 2,318,607	$ 285,098	$ (201,680)	$ 2,402,025

* Nuclear fuel decreases represent amortization of $46.5 million.

The 2012 construction plan includes authorization for future expenditures of $155.7 million. These expenditures will be funded from existing bond proceeds, revenues, other available funds, and additional financings as deemed appropriate.

3. CASH AND INVESTMENTS:

The District follows GASB Cod. Sec. In5, *Investment Pools (External)* ("GASB Cod. Sec. In5"). GASB Cod. Sec. In5 requires the District's investments to be recorded at fair value with the changes in the fair value of investments reported as Investment income in the accompanying Statements of Revenues, Expenses, and Changes in Fund Equity. The District had an unrealized net gain of $14.0 million as of December 31, 2011, and an unrealized net loss of $1.4 million as of December 31, 2010. Included in these amounts are an unrealized net gain on decommissioning funds of $12.6 million as of December 31, 2011 and an unrealized net loss on decommissioning funds of $0.2 million as of December 31, 2010.

Cash deposits, primarily interest bearing, are covered by federal depository insurance or pledged collateral of U.S. Government securities held by various depositories. Investments were in U.S. Government securities and Federal Agency obligations held in the District's name by the custodial banks. Cash and investments totaled $1,084.1 million and $1,059.0 million at December 31, 2011 and 2010, respectively.

The fair value of all cash and investments, regardless of balance sheet classification, as of December 31 was as follows (000's):

	2011	2010
U.S. Treasury and government agency securities	$ 656,516	$ 712,340
Corporate bonds	150,850	160,550
Municipal bonds	16,295	15,613
Certificates of deposit	257	1,014
Cash and money market mutual funds	260,212	169,440
Total cash and investments	$ 1,084,130	$ 1,058,957

The fair value of the District's Special Purpose Funds as of December 31 are as follows (000's):

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

	2011	2010
Construction funds - Cash and cash equivalents	$ 23,870	$ —
Construction funds - Investments	135,245	286,997
	$ 159,115	$ 286,997

The Debt reserve fund, as established under the Resolution, consists of a Primary account and a Secondary account. The District is required by the Resolution to maintain an amount equal to 50% of the maximum amount of interest accrued in the current or any future year in the Primary account. Such amount totaled $51.1 million and $50.2 million as of December 31, 2011 and 2010, respectively. The Secondary account can be established at such amounts and can be utilized for any lawful purpose as determined by the District's Board of Directors. Such account totaled $52.7 million and $51.7 million as of December 31, 2011 and 2010, respectively.

	2011	2010
Debt reserve fund - Cash and cash equivalents	$ 50	$ 17
Debt reserve fund - Investments	103,756	101,925
	$ 103,806	$ 101,942

The Employee benefit funds consist of a self-funded hospital-medical benefit plan and a retired employee life insurance benefit plan. The District pays 80% of the hospital-medical premiums with the employees paying the remaining 20% of the cost of such coverage. The plan had contributed funds of $7.7 million and $7.5 million at

December 31, 2011 and 2010, respectively. The retired employee life insurance benefit plan was funded prior to the adoption of GASB Cod. Sec. P50, *Postemployment Benefits Other Than Pension Benefits - Employer Reporting* ("GASB Cod. Sec. P50") and creation of an irrevocable grantor trust for postretirement health and life insurance benefits. For additional information on postemployment benefits see Note 16. The District pays the total cost of the employee life insurance benefit once the employee retires. The plan had contributed funds of $1.7 million and $1.9 million at December 31, 2011 and 2010, respectively. Both funds are held by outside trustees in compliance with the funding plans approved by the District's Board of Directors.

	2011	2010
Employee benefit fund - Cash and cash equivalents	$ 4,696	$ 2,433
Employee benefit fund - Investments	4,697	6,982
	$ 9,393	$ 9,415

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

	2011	2010
Decommissioning funds	$ 517,950	$ 484,130

4. FAIR VALUE OF FINANCIAL INSTRUMENTS:

As defined in ASC 820, fair value is the exchange price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date.

ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in an active market for identical assets or liabilities and the lowest priority to unobservable inputs. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels of fair value hierarchy defined in ASC 820 are as follows:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The District currently does not have Level 1 assets and liabilities included in the Decommissioning funds, other Special Purpose Funds, or Investments in Current Assets.

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

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

Level 2 assets and liabilities primarily include U.S. treasury and other federal agency securities and corporate bonds held in the District's Decommissioning funds, other Special Purpose Funds, and certain Investments in Current Assets. The District's investment in cash and money market mutual funds are excluded from the ASC 820 fair value hierarchy.

Level 3 - Pricing inputs include significant inputs that are unobservable and cannot be corroborated by market data. Level 3 assets and liabilities are valued based on internally developed models and assumptions or methodologies using significant unobservable inputs. The District currently does not have Level 3 assets or liabilities included in the Decommissioning funds, other Special Purpose Funds, or Investments in Current Assets.

The District performs an analysis annually to determine the appropriate hierarchy level classification of the assets and liabilities that are included within the scope of ASC 820. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

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

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Available-for-sale securities:				
U.S. Treasury and government agency securities	$ —	$ 325,216	$ —	$ 325,216
Certificates of deposit	—	257	—	257
Decommissioning funds:				
U.S. Treasury and government agency securities	—	331,300	—	331,300
Corporate bonds	—	150,850	—	150,850
Municipal bonds	—	16,295	—	16,295
	$ —	$ 823,918	$ —	$ 823,918

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Available-for-sale securities:				
U.S. Treasury and government agency securities	$ —	$ 444,939	$ —	$ 444,939
Certificates of deposit	—	1,014	—	1,014
Decommissioning funds:				
U.S. Treasury and government agency securities	—	267,401	—	267,401
Corporate bonds	—	160,550	—	160,550
Municipal bonds	—	15,613	—	15,613
	$ —	$ 889,517	$ —	$ 889,517

Decommissioning funds reflect the assets held in trust to cover general decommissioning costs and consist primarily of fixed income governmental securities.

5. LONG-TERM CAPACITY CONTRACTS:

Long-term capacity contracts include the District's $198.2 million share of the construction costs of Omaha Public Power District's ("OPPD") 682 MW Nebraska City Station Unit 2 ("NC2") coal-fired power plant which amount includes $15.8 million share of associated transmission facilities construction costs. The District has entered into a participation power agreement with OPPD for a 23.7% share of the power from this plant. NC2 began commercial operation on May 1, 2009, at which time the District began amortizing the amount of the capacity contract associated with the plant of $182.4 million on a straight-line basis over the 40-year estimated useful life of the plant. In July 2011, OPPD refunded the District $4.9 million representing excess construction costs and this amount was credited to Power purchased and $3.2 million of prepaid transmission costs were transferred to prepaid purchase power due to finalized construction costs. Accumulated amortization was $12.2 million in 2011 and $7.6 million in 2010. The unamortized amount of the plant capacity contract was $173.4 million and $174.8 million as of December 31, 2011 and 2010, respectively, of which $4.6 million was included in Prepayments and other current assets as of December 31, 2011 and 2010. The costs of the transmission facilities are being returned to the District in the form of a credit on the District's monthly transmission bill from OPPD. Accumulated credits were $9.2 million in 2011 and $5.7 million in 2010. The remaining transmission credits were $3.3 million and $10.1 million as of December 31, 2011 and 2010, respectively, of which $3.3 million was included in Prepayments and other current assets as of December 31, 2011 and 2010.

Long-term capacity contracts also include the District's purchase of the capacity of a 50 MW hydroelectric generating facility owned and operated by The Central Nebraska Public Power and Irrigation District ("Central"). The District is recording amortization on a straight-line basis over the 40-year estimated useful life of the facility. Accumulated amortization was $52.8 million in 2011 and $50.4 million in 2010. The unamortized amount of the Central capacity contract was $33.9 million and $36.3 million as of December 31, 2011 and 2010, respectively, of which $2.3 million was included in Prepayments and other current assets as of December 31, 2011 and 2010.

The District has an agreement whereby Central makes available all the production of the facility and the District pays all costs of operating and maintaining the facility plus a charge based on the amount of energy delivered to the District. Costs of $2.5 million and $1.4 million in 2011 and 2010, respectively, are included in Power purchased in the accompanying Statements of Revenues, Expenses, and Changes in Fund Equity.

6. DEFERRED SETTLEMENT CHARGES:

The District deferred the cost of a $39.1 million payment to MidAmerican Energy Company ("MEC") in 2002 in conjunction with the settlement of litigation with respect to the operation of CNS. The deferred costs of the MEC payment will be recognized as expense in future rate periods when such costs are included in the revenue requirements used to establish electric rates. The balance of such deferral was $10.2 million and $14.9 million as of December 31, 2011 and 2010, respectively, of which $5.0 million and $4.7 million was included in Prepayments and other current assets as of December 31, 2011 and 2010, respectively.

7. INVESTMENT IN THE ENERGY AUTHORITY:

The District is a member of The Energy Authority ("TEA"), a power marketing corporation. TEA assumes the wholesale power marketing responsibilities of its members with each member having ownership in the joint venture. TEA has access to approximately 25,000 megawatts of its members' and partners' generation located across the nation. TEA also provides its members with natural gas procurement or contract management services for gas used in the generation of electricity and for local distribution. TEA provides the District with gas contract management services.

The table below contains the condensed financial information for TEA as of December 31, (000's):

Condensed Balance Sheet	2011	2010
Current Assets	$ 143,275	$ 139,924
Noncurrent and Restricted Assets	21,427	25,787
Total Assets	$ 164,702	$ 165,711
Current Liabilities	$ 116,743	$ 113,452
Noncurrent Liabilities	3,364	5,359
Net Assets	44,595	46,900
Total Liabilities and Net Assets	$ 164,702	$ 165,711
Condensed Statement of Operations		
Revenues	$ 1,183,953	$ 947,153
Energy Costs	(1,060,373)	(824,094)
Gross Profit	123,580	123,059
Operating Expenses	(40,066)	(35,131)
Operating Income	83,514	87,928
Non-Operating Income	254	415
Increase in Net Assets	$ 83,768	$ 88,343

At December 31, 2011 and 2010, the District had a 20.0% ownership interest in TEA. All of TEA's revenues and costs are allocated to the members. TEA's net revenues are allocated among the members based upon a combination of each respective member's purchased power and power sales transactions and natural gas transactions with TEA and each member's ownership interest.

The following table summarizes the transactions applicable to the District's investment in TEA as of December 31, (000's):

	2011	2010
Beginning Balance	$ 7,614	$ 6,776
Reduction to power costs and increase in electric revenues	34,785	32,300
Distributions from TEA	(30,462)	(26,791)
Other expenses	(3,182)	(4,671)
Ending Balance	$ 8,755	$ 7,614

The District's power purchases and sales with TEA are reflected in the Statements of Revenues, Expenses, and Changes in Fund Equity as Power purchased, and Operating Revenues, respectively. For the years ended

December 31, 2011 and 2010, the District recorded Operating Revenues of $79.3 million and $66.6 million, respectively, and Power purchased expenses of $2.6 million for both years.

At December 31, 2011 and 2010, $7.1 million and $8.3 million due from TEA was included in Receivables and $0.4 million and $0.5 million due to TEA was included in Accounts payable, and accrued liabilities respectively.

As of December 31, 2011, the District is obligated to guaranty, directly or indirectly, TEA's electric trading activities in an amount up to $28.9 million plus attorney's fees which any party claiming and prevailing under the guaranty might incur and be entitled to recover under its contract with TEA. Generally, the District's guaranty obligations for electric trading would arise if TEA did not make the contractually required payment for energy, capacity, or transmission which was delivered or made available or if TEA failed to deliver or provide energy, capacity, or transmission as required under a contract.

The District's exposure relating to TEA is limited to the District's capital investment in TEA, any accounts receivable from TEA, and trade guarantees provided to TEA by the District. These guarantees are within the scope of ASC 460, *Guarantees*. Upon the District making any payments under its electric guaranty, it has certain contribution rights with the other members of TEA in order that payments made under the TEA member guaranties would be equalized ratably, based upon each member's equity ownership interest in TEA. After such contributions have been effected, the District would only have recourse against TEA to recover amounts paid under the guaranty. The term of this guaranty is generally indefinite, but the District has the ability to terminate its guaranty obligations by causing to be provided advance notice to the beneficiaries thereof. Such termination of its guaranty obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. As of December 31, 2011 and 2010, the District has not recorded a liability related to these guaranties.

8. REVENUE BONDS:

In May 2011, the District issued General Revenue Bonds, 2011 Series A, in the amount of $61.4 million to refund $64.2 million of TCP notes.

In September 2010, the District issued General Revenue Bonds, 2010 Series A and 2010 Series C, in the amount of $114.1 million and $147.1 million, respectively, to finance $164.8 million of the costs of certain generation, transmission, and distribution capital additions, to refund $77.6 million of TCP notes, and to refund $16.8 million of TECP notes. Also in September 2010, the District issued General Revenue Bonds, 2010 Series B, in the amount of $8.4 million to refund $8.2 million of TCP notes.

Debt service payments and principal payments of the General Revenue Bonds as of December 31, 2011, are as follows (000's):

Year	Debt Service Payments	Principal Payments
2012[1]	$ 257,275	$ 161,565
2013[2]	406,994	318,650
2014	180,451	107,665
2015	158,370	90,530
2016	156,506	92,950
2017–2021	592,661	330,140
2022–2026	498,748	312,980
2027–2031	371,631	261,905
2032–2036	243,697	195,200
2037–2041	89,566	77,505
2042	5,366	5,090
Total Payments	$ 2,961,265	$ 1,954,180

(1) Includes the $29,180 principal amount of the 2009 Series B Taxable Term Bonds maturing January 1, 2013, which the District expects to refinance.

(2) Includes the $137,765 principal amount of the 2008 Series A Taxable Term Bonds and the $70,820 principal amount of the 2009 Series B Taxable Term Bonds maturing January 1, 2014, which the District expects to refinance.

The fair value of outstanding revenue bonds is determined using currently published rates. The fair value is estimated to be $2,109.2 million and $2,072.8 million at December 31, 2011 and 2010, respectively.

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

December 31,	Interest Rate	2011	2010
General Revenue Bonds:			
1999 Series A Serial Bonds 2010–2011	4.70% - 5.00%	$ —	$ 165
2002 Series B:			
Serial Bonds 2011–2025	5.00%	37,290	43,030
Term Bonds 2026–2032	5.00%	22,885	22,885
2003 Series A:			
Serial Bonds 2011–2026	3.75% - 5.00%	87,680	91,900
Term Bonds 2027–2034	5.00%	86,095	86,095
2004 Series B Serial Bonds 2011–2013	4.25% - 5.00%	73,925	117,395
2005 Series A Serial Bonds 2011–2025	3.125% - 5.25%	81,110	85,105
2005 Series B-1 Serial Bonds 2011–2015	5.00%	54,915	65,570
2005 Series B-2 Serial Bonds 2011–2016	4.00% - 5.00%	52,815	52,815
2005 Series C:			
Serial Bonds 2011–2025, 2040	3.50% - 5.125%	71,630	73,030
Term Bonds			
2026–2029	5.00%	11,765	11,765
2030–2034	4.75%	18,240	18,240
2035–2040	5.00%	27,500	27,500
2006 Series A:			
Serial Bonds 2011–2025	4.00% - 5.00%	69,585	73,855
Term Bonds			
2026–2030	5.00%	18,680	18,680
2031–2035	5.00%	23,840	23,840
2036–2040	4.375%	400	400
2036–2040	5.00%	30,020	30,020
2007 Series B:			
Serial Bonds 2011–2026	4.00% - 5.00%	202,800	222,795
Term Bonds			
2027–2031	4.65%	36,140	36,140
2032–2036	5.00%	19,270	19,270
2008 Series A Taxable Term Bonds 2013	5.14%	137,765	137,765
2008 Series B:			
Serial Bonds 2011–2029	3.00% - 5.00%	222,495	230,790
Term Bonds			
2030–2032	5.00%	32,390	32,390
2033–2037	5.00%	50,880	50,880
2038–2040	5.00%	7,180	7,180
2009 Series A Taxable Build America Bonds:			
Term Bonds			
2019–2025	6.606%	17,465	17,465
2026–2034	7.399%	32,890	32,890
2009 Series B Taxable:			
Term Bonds			
2012	4.135%	29,180	29,180
2013	4.85%	70,820	70,820
2009 Series C Serial Bonds 2011–2019	2.50% - 4.25%	13,895	15,585
2010 Series A Taxable Build America Bonds:			
Serial Bonds 2019–2024	3.98% - 4.73%	31,875	31,875
Term Bonds			
2025–2029	5.323%	27,985	27,985
2030–2042	5.423%	54,190	54,190
2010 Series B Taxable Serial Bonds 2011–2020	1.33% - 4.18%	7,485	8,220
2010 Series C:			
Serial Bonds 2011–2025	3.50% - 5.00%	118,960	125,475
Term Bonds			
2026–2030	4.00%	6,165	6,165
2026–2030	5.00%	14,180	14,180
2011 Series A Serial Bonds 2011–2016	1.50% - 5.00%	51,795	—
Total par amount of revenue bonds		1,954,180	2,013,530
Unamortized premium net of discount		39,095	41,343
		1,993,275	2,054,873
Less - current maturities of revenue bonds		(161,565)	(111,145)
Total revenue bonds		$ 1,831,710	$ 1,943,728

9. COMMERCIAL PAPER NOTES:

The District is authorized to issue up to $150.0 million of TECP notes. A $150.0 million credit agreement expiring August 1, 2014, is maintained with two commercial banks to support the sale of the TECP notes. The District had a $200.0 million credit agreement to support the sale of TCP notes which expired on August 1, 2011. This agreement was not renewed. The District had $110.0 million and $122.0 million of TECP notes outstanding at December 31, 2011 and 2010, respectively. The proceeds of the TECP notes have been used to provide short-term financing for certain capital additions and for other lawful purposes of the District. The District had $98.9 million of TCP notes outstanding at December 31, 2010. The proceeds of the TCP notes had been used to purchase nuclear fuel and to fund capital projects at CNS. The effective interest rates on outstanding TECP notes for 2011 and 2010 were 0.2% and 0.3%, respectively. The effective interest rates on outstanding TCP notes for 2011 and 2010 were 0.2% and 0.4%, respectively.

The $110.0 million of TECP notes outstanding at December 31, 2011 are anticipated to be retired by future collections through electric rates and issuance of revenue bonds. The carrying value of the commercial paper notes approximates market value due to the short-term nature of the notes.

10. LINE OF CREDIT AGREEMENTS:

The District has a line of credit agreement of $150.0 million that supports the payment of the principal outstanding of the TECP notes. See Note 9 for additional information. At December 31, 2011 and 2010, no amounts have been drawn on the line of credit.

11. REVOLVING CREDIT AGREEMENTS:

In 2011, the District entered into two revolving credit agreements. The District is authorized to borrow up to $150.0 million under a TERCA and up to $50.0 million under a TRCA. A $150.0 million revolving credit agreement and a $50.0 million revolving credit agreement, expiring August 1, 2014 and November 30, 2014, respectively, are maintained with a commercial bank to provide for these borrowings. The District had $109.0 million and $6.1 million of TERCA and TRCA, respectively, outstanding at December 31, 2011. The borrowings are to provide short-term financing for certain capital additions and for other lawful purposes of the District.

The $109.0 million of TERCA and the $6.1 million of TRCA outstanding at December 31, 2011 are anticipated to be retired by future collections through electric rates and issuance of revenue bonds. The carrying value of the revolving credit agreements approximates market value due to the short-term nature of the agreements.

12. LONG-TERM DEBT:

Long-term debt activity, net of current activity for the year ended December 31, 2011, was as follows (000's):

	December 31, 2010	Increases	Decreases	December 31, 2011	Principal Amounts Due Within One Year
Revenue bonds	$ 1,943,728	$ 68,391	$ (180,409)	$ 1,831,710	$ 161,565
Commercial paper notes	220,872	475,166	(586,038)	110,000	—
Revolving credit agreements	—	115,100	—	115,100	—
Total long-term debt activity	$ 2,164,600	$ 658,657	$ (766,447)	$ 2,056,810	$ 161,565

13. ASSET RETIREMENT OBLIGATION:

The District has recorded an obligation for the fair value of its legal liability for asset retirement obligations associated with CNS, various ash landfills at its two coal-fired power stations, removal of asbestos at the District's various coal, gas, and hydro generating facilities, polychlorinated biphenyls from substation and distribution equipment, and underground storage tanks as well as abandonment of water wells. In 2010, the District reevaluated its asset retirement obligation ("ARO") associated with CNS after receiving approval from the Nuclear Regulatory Commission ("NRC") to extend its operating license by 20 years. As a result, an adjustment to decrease the ARO by $145.6 million was made primarily related to changes to timing of decommissioning of CNS.

The total asset retirement obligation liability recorded by the District was $885.5 million and $843.7 million as of December 31, 2011 and 2010, respectively, and is included in the Deferred Credits and Other Liabilities section of the accompanying Balance Sheets.

The following table shows costs as of January 1, and charges to the ARO that occurred during the years ended December 31, 2011 and 2010, and are included in Deferred Credits and Other Liabilities section of the accompanying Balance Sheets as of December 31, (000's):

For the Year Ended December 31,	2011	2010
Balance, beginning of year	$ 843,741	$ 943,647
Accretion	41,788	45,735
ARO adjustment	—	(145,641)
Balance, end of year	$ 885,529	$ 843,741

A significant amount of the ARO is funded by decommissioning funds of $518.0 million and $484.1 million as of December 31, 2011 and 2010, respectively. See Note 3 for additional information.

At the time the liability for the asset retirement is incurred, ASC 410 requires capitalization of the costs to the related asset. For asset retirement obligations existing at the time of adoption of ASC 410, the statement requires capitalization of costs at the level that existed at the time of incurring the liability. These capitalized costs are depreciated over the same period as the related asset. At the date of adoption, the depreciation expense for past periods was recorded as a regulatory asset in accordance with ASC 980 because the District will be able to recover these costs in future rates.

The initial liability is accreted to its present value each period. The District defers this accretion as a regulatory asset based on its determination that these costs can be collected from customers. Accretion was $41.8 million and $45.7 million for 2011 and 2010, respectively.

14. PAYMENTS IN LIEU OF TAXES:

The District is required to make payments in lieu of taxes, aggregating 5% of the gross revenue derived from electric retail sales within the city limits of incorporated cities and towns served directly by the District. Such payments totaled $9.2 million and $8.3 million for the years ended December 31, 2011 and 2010, respectively.

15. RETIREMENT PLAN:

The District's Employees' Retirement Plan (the "Plan") is a defined contribution pension plan established by the District to provide benefits at retirement to regular full-time and part-time employees of the District. At December 31, 2011, there were 2,127 Plan members. Plan members are required to contribute a minimum of 2%, up to a maximum of 5%, of covered salary. The District is required to contribute two times the Plan member's contribution based on covered salary up to $40,000. On covered salary greater than $40,000, the District is required to contribute one times the Plan member's contribution. Plan provisions and contribution requirements are established and may be amended by the District's Board of Directors. The District's contribution was $12.0 million for 2011 and $12.1 million for 2010 of which $1.2 million was accrued and in Accounts payable and accrued liabilities for each of the years ended December 31, 2011 and 2010.

16. POSTEMPLOYMENT BENEFITS OTHER THAN PENSIONS:

A. Plan Description -

The District administers a single-employer defined benefit healthcare plan that provides lifetime healthcare insurance for eligible retirees and their spouses. Eligibility and benefit provisions are established by the District's Board of Directors. In addition, the District provides employees a $5,000 death benefit when they retire and substantially all of the District's retired and active employees are eligible for such benefit.

B. Funding Policy -

The eligibility and contributions of the plan members and the funding policy of the plan is established and may be amended by the District's Board of Directors. The District, for employees hired on or prior to December 31, 1992, pays all or part of the cost (determined by retirement age) of certain hospital-medical premiums when these employees retire. The District amended the plan effective January 1, 1993. Employees hired on or after January 1, 1993, are subject to a contribution cap that limits the District's portion of the cost of such coverage to the full premium the year the employee retired or the amount at the time the employee reaches age 65, or the year in which the employee retires if older than age 65. Any increases in the cost of such coverage in subsequent years would be paid by the retired employee. The District amended the plan effective January 1, 1999. Employees hired on or after January 1, 1999, are not eligible for postretirement hospital-medical benefits once they reach age 65 or Medicare eligibility. The District amended the plan effective January 1, 2004, to provide that employees hired on or after that date will not be eligible for postretirement hospital-medical benefits once they retire. The District amended the plan effective July 1, 2007, to provide that any former employee who is rehired will receive credit for prior years of service. The District further amended the plan effective September 1, 2007, to provide that employees hired or rehired on or after that date must work five consecutive years immediately prior to retirement to be eligible for postretirement hospital-medical benefits once they retire.

C. Annual OPEB Cost and Net OPEB Obligation -

The District's annual Other Postemployment Benefits ("OPEB") cost (expense) is calculated based on the annual required contribution ("ARC"), an amount actuarially determined in accordance with the parameters of GASB Cod. Sec. P50. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover the normal cost each year (or benefits earned in the current year) and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years. The following table shows the components of the District's OPEB cost for the year, the amount actually contributed to the plan, and changes in the District's net OPEB obligation as of December 31, (000's):

For the Year Ended December 31,	2011	2010	2009
Annual required contribution	$ 33,330	$ 30,932	$ 33,143
Interest on net OPEB obligation	4,614	3,566	2,369
Adjustment to annual required contribution	(4,009)	(2,992)	(3,536)
Annual OPEB cost	33,935	31,506	31,976
Contributions made	(21,018)	(13,282)	(11,156)
Increase in net OPEB obligation	12,917	18,224	20,820
Net OPEB obligation - beginning of year	80,244	62,020	41,200
Net OPEB obligation - end of year	$ 93,161	$ 80,244	$ 62,020

The District's annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net OPEB obligation for 2011, 2010, and 2009 were as follows (dollar amounts in thousands):

Year	Annual OPEB Cost	Percentage of Annual OPEB Cost Contributed	Net OPEB Obligation
2011	$ 33,935	61.9%	$ 93,161
2010	$ 31,506	42.2%	$ 80,244
2009	$ 31,976	34.9%	$ 62,020

D. Funded Status and Funding Progress -

In 2008, the District established an irrevocable trust to begin funding the unamortized OPEB obligation. Total contributions to the plan in 2011 were $21.0 million which included $10.0 million paid to the trust and $11.0 million for the cost of benefits. Total contributions to the plan in 2010 were $13.3 million which included $4.0 million paid to the trust and $9.3 million for the cost of benefits. Total contributions to the plan in 2009 were $11.2 million which included $4.0 million paid to the trust and $7.2 million for the cost of benefits. It is currently projected that funding above the pay-as-you-go amount will remain at $4.0 million through 2012 and increase to $10.0 million in 2013. The final funding will be determined annually by the District's Board of Directors. The trust is currently projected to be fully funded by 2033.

The Actuarial Accrued Liability ("AAL") is the present value of benefits attributable to past accounting periods. The AAL was $427.7 million, $404.6 million, and $415.2 million as of January 1, 2011, 2010, and 2009, respectively. The AAL is presented in the table below based on the actuarial valuation as of January 1, (000's):

	Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) (b)	Unfunded Actuarial Accrued Liability (UAAL) (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAAL to Covered Payroll ((b-a)/c)
2011	$ 15,086	$ 427,709	$ 412,623	3.5%	$ 189,428	218%
2010	$ 10,147	$ 404,646	$ 394,498	2.5%	$ 182,315	216%
2009	$ 6,268	$ 415,243	$ 408,975	1.5%	$ 185,200	221%

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the healthcare cost trend. Amounts determined regarding the funded status of the plan and the annual required contributions of the employer are subject to continual revision as actual results are compared with past expectations and new estimates are made about the future.

E. Actuarial Methods and Assumptions -

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan as understood by the employer and the plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the employer and plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations.

In the January 1, 2010 actuarial valuation, which is the most recent actuarial study, the Unit Credit Actuarial Cost method was used for 2011, 2010, and 2009. In 2011, the actuarial assumptions included an annual healthcare cost trend rate of 7.2% initially, reduced by decrements to an ultimate rate of 4.4%. In 2010, the actuarial assumptions included an annual healthcare cost trend rate of 7.7% initially, reduced by decrements to an ultimate rate of 4.4%. In 2009, the actuarial assumptions included an annual healthcare cost trend rate of 8.3% initially, reduced by decrements to an ultimate rate of 4.6%. The discount rate used for all three years was 5.75% which was based on the District's return on internal investments used to fund benefit payments blended with the expected return on assets of the OPEB Trust Fund. An inflation rate of 3.5% was also assumed for all three years. Amortization for the initial unfunded AAL was determined using a closed period of 30 years and the level percentage of projected payroll method assuming 4.0% payroll growth was used for all three years.

F. Market Value of Plan Investments -

The actuarial valuation of plan assets was based on market values as of January 1, 2010. The investments in the OPEB plan include corporate and government debt, foreign and domestic stocks, mutual funds and cash. The market value of plan assets was $24.9 million, $15.3 million, and $10.1 million at December 31, 2011, 2010, and 2009, respectively.

17. COMMITMENTS AND CONTINGENCIES:

A. Fuel Commitments -

The District has various coal supply contracts and a coal transportation contract with minimum future payments of $455.0 million. The coal supply contracts expire at various times through the end of 2014. The coal transportation contract is in place sufficient to deliver coal to the generation facilities through the expiration date of the aforementioned contract and is subject to price escalation adjustments.

B. Power Purchase and Sales Agreements -

The District has wholesale power purchase commitments with the Western Area Power Administration through 2020 with annual minimum future payments of approximately $37.8 million. These purchases are subject to rate changes.

Effective January 2004, the District entered into a participation power agreement (the "NC2 Agreement") with OPPD to receive 23.7% of the output of NC2, estimated to be 162 MW of the power from the 682 MW coal-fired

power plant constructed by OPPD. NC2 began commercial operation on May 1, 2009. OPPD will retain 50.0% of the output for its own use and has entered into similar participation power sales agreements with other power purchasers. The District's obligation under the NC2 Agreement to make payments is an unconditional "take-or-pay" obligation, obligating the District to make such payments whether or not NC2 or any part thereof is completed, delayed, terminated, available, operable, operating, or retired. The NC2 Agreement contains a step-up provision obligating the District to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs, and reserves related to NC2 as a result of a defaulting power purchaser. The District's obligation pursuant to such step-up provision is limited to 160.0% of its original participation share (23.7%).

The District has entered into a power purchase agreement with Central for the purchase of the net power and energy produced by the Kingsley Project during its operating life. The Kingsley Project is a hydroelectric generating unit at the Kingsley Dam in Keith County, Nebraska with an accredited net capacity of 36 MW.

The District has entered into a hydro power purchase agreement with Central through December 31, 2013 for the purchase of the net power and energy produced by three hydroelectric plants (excludes the Kingsley Project) owned and operated by Central. Accredited capacity of the three hydroelectric plants is 54 MW.

The District has entered into power sales agreements with Lincoln Electric System ("LES") for the sale to LES of 30% of the net power and energy of Sheldon Station ("Sheldon") and 8% of the net power and energy of Gerald Gentleman Station ("GGS"). In return, LES agrees to pay 30% and 8% of all costs attributable to Sheldon and GGS, respectively. Each agreement is to terminate upon the later of the last maturity of the debt attributable to the respective station or the date on which the District retires such station from commercial operation.

The District had a power sales agreement with KCPL for the sale to KCPL of 100 MW of the power and energy from GGS through May 31, 2011. This agreement was not renewed.

The District has entered into a participation power sales agreement with KCPL for the sale to KCPL of 75 MW of accredited capacity from CNS through January 18, 2014.

The District has a participation power sales agreement with Heartland Consumers Power District ("Heartland") for the sale to Heartland of 45 MW of accredited capacity from CNS through December 31, 2013.

The District had a participation power sales agreement with Municipal Energy Agency of Nebraska ("MEAN") for the sale to MEAN of the power and energy from GGS and CNS of 95 MW from July 1, 2008 through December 31, 2010, as amended, and 45 MW from January 1, 2011 through the last day of the month prior to the commercial operation of the Whelan Energy Center 2 ("WEC2") fossil plant. MEAN has an ownership interest in WEC2, a 220 MW coal-fired power plant, which began commercial operation May 1, 2011. This agreement was not renewed.

The District has entered into a participation power sales agreement with MEAN for the sale to MEAN of the power and energy from GGS and CNS of 50 MW from January 1, 2011 through December 31, 2023.

The District has entered into participation power agreements with OPPD, MEAN, JEA (formerly the Jacksonville Electric Authority) and Grand Island Utilities for the sale of power from the 60 MW Ainsworth Wind Energy Facility. The participation power agreements are each for a term of 20 years and in the following amounts: OPPD for 16.8%; MEAN for 11.8%; JEA for 16.8%; and Grand Island Utilities for 1.7%.

The District has entered into a 20-year power purchase agreement with Elkhorn Ridge Wind, LLC to purchase all electric power from the 80 MW Elkhorn Ridge Wind Facility. The District has also entered into power sales agreements with OPPD, MEAN, LES, and Grand Island Utilities for the sale of power from the Elkhorn Ridge Wind Facility. The power sales agreements are each for a term of 20 years and in the following amounts: OPPD for 31.3%; MEAN for 10.0%; LES for 7.5%; and Grand Island Utilities for 1.3%.

The District has entered into a 20-year power purchase agreement with Laredo Ridge Wind, LLC to purchase all electric power from the 80 MW Laredo Ridge Wind Facility, which began commercial operation on February 1, 2011. The District has also entered into power sales agreements with LES, MEAN, and Grand Island Utilities for the sale of power from the Laredo Ridge Wind Facility. The power sales agreements are each for a term of 20 years and in the following amounts: LES for 12.5%; MEAN for 10.0%; and Grand Island Utilities for 1.3%.

The District has entered in a 20-year power purchase agreement with Bluestem, LLC to purchase all electric power from a 3 MW wind facility developed near Springview, Nebraska, which began commercial operation on October 1, 2011.

The District has entered into a 20-year power purchase agreement with Broken Bow Wind, LLC to purchase all electric power from the 80 MW Broken Bow Wind Facility planned for development near Broken Bow, Nebraska. Construction of this facility has commenced and is scheduled to begin commercial operation in December 2012. The District plans to sell 37 MW of the capacity of this project to other utilities in Nebraska.

The District has entered into a 25-year power purchase agreement with Broken Bow Wind II, LLC to purchase all electric power from the 75 MW Broken Bow Wind II Facility planned for development near Broken Bow,

Nebraska. Construction of this facility has commenced and is scheduled to begin commercial operation in December 2012. The District has also entered into a 25-year power sales agreement with OPPD for the sale of 60% of the power from the Broken Bow Wind II Facility.

The District had entered into a 20-year power purchase agreement with Community Wind Energy Transmission, LLC to purchase all electric power from the 42 MW Crofton Hills Wind Facility near Crofton, Nebraska. In 2011, Edison Mission Energy acquired the project and re-named it Crofton Bluffs Wind Facility resulting in a restated and amended agreement. The facility is planned for development in late 2012. The District plans to sell one-half of the capacity of this project to other utilities in Nebraska.

The District has 20-year wholesale power contracts, with a term that expires December 31, 2021, with the majority of its firm requirements wholesale customers to provide them with their total power and energy requirements through 2007, after which the wholesale customer could level-off its power and energy purchases through 2010 and thereafter could reduce its power and energy purchases up to 10.0% per year with at least three years advance notice. On March 16, 2011, the District received notice from the City of Neligh stating that they desire to terminate their wholesale power contract effective April 1, 2012. The City of Neligh is among the few firm requirements wholesale customers who do not have wholesale power contracts with the previously described 20-year term.

The District has entered into long-term PRO Agreements having initial terms of 15, 20, or 25 years with 79 municipalities for the operation of certain retail electric distribution systems. These PRO Agreements expire on various dates between January 1, 2016 and May 1, 2033. These PRO Agreements obligate the District to make payments based on gross revenues from the municipalities and pay for normal property additions during the term of the agreement.

C. Transmission Agreements -

On April 1, 2009, the District became a member of the Southwest Power Pool ("SPP"), a regional transmission organization based in Little Rock, Arkansas. Membership in SPP provides the District reliability coordination service, generation reserve sharing, regional tariff administration, including generation interconnection service, network, and point-to-point transmission service, and regional transmission expansion planning. The District is able to participate in SPP's energy imbalance market, a real-time balancing market that provides members the opportunity to have SPP dispatch resources based on marginal cost.

The District entered into a WEC2 Transmission Facilities Agreement effective August 13, 2007, with the Public Power Generation Agency ("PPGA") and the City of Hastings, Nebraska. This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of WEC2 to the District's transmission system. WEC2 began commercial operation on May 1, 2011. Cost of the project was $11.8 million and is to be paid by PPGA. PPGA has advanced all required payments to the District. These advance payments are prepaid transmission service on the District's transmission system for delivery of the Participant's Participation Power.

The District entered into a Transmission Facilities Construction Agreement effective June 15, 2009, with TransCanada Keystone Pipeline, LP ("Keystone"). This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of Keystone to the District's transmission system. Cost of the project was $8.4 million and repayment by Keystone, over a ten-year period, began in July 2010 with a remaining balance due the District of $7.6 million as of December 31, 2011.

The District entered into a second Transmission Facilities Construction Agreement effective July 17, 2009, with TransCanada Keystone XL Pipeline, LP ("Keystone XL"). This agreement addresses the transmission facilities, construction, cost allocation, payment, and applicable cost recovery for the interconnection and delivery facilities required for the interconnection of Keystone XL to the District's transmission system. The initial estimated cost of the project was $52.9 million and was to be paid by Keystone XL over a ten-year period anticipated to begin July 2013. However, the project was recently delayed due to routing concerns of the pipeline across the Nebraska Sandhills. Adjustments to the facilities, project costs, and completion schedules will be made once the final route is determined, which is anticipated in the fourth quarter of 2012. Keystone XL remains responsible for all present and future project costs. As of December 31, 2011, actual project costs totaled $7.6 million.

D. Cooper Nuclear Station -

Under the provisions of the Federal Price-Anderson Act, the District and all other licensed nuclear power plant operators could each be assessed for claims in amounts up to $117.5 million per unit owned in the event of any nuclear incident involving any licensed facility in the nation, with a maximum assessment of $17.5 million per year

per incident per unit owned. To satisfy this potential obligation, the District has submitted its most recent audited financial statements to the NRC.

The NRC evaluates nuclear plant performance as part of its reactor oversight process ("ROP"). The NRC has five performance categories included in the ROP Action Matrix Summary that is part of this process. As of December 31, 2011, CNS was in the Regulatory Response Column, which is the second highest of the five NRC defined performance categories, and had been in this column since the first quarter of 2011. CNS returned to the Licensee Response Column, which is the first or best of the five NRC defined performance categories, during the first quarter of 2012. This improved column placement in 2012 is due to the satisfactory resolution of a White Inspection Finding associated with an NRC Fire Protection Inspection that identified an error in a fire protection procedure.

Since the earthquake and tsunami of March 11, 2011, that impacted the Fukushima Dai-ichi Plants in Japan, the District, as well as the rest of the nuclear industry, has been working to first understand the events that damaged the reactors and associated fuel storage pools and then look to any changes that might be necessary at the United States nuclear plants. Of particular interest is the performance of the General Electric boiling water reactor with Mark 1 containment systems in Japan and their on-site used fuel storage facilities. CNS utilizes this same containment system; however, significant improvements to the design have been made over the life of the plant.

A NRC Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident was published on July 12, 2011 that included 12 recommendations for improvements for U.S. reactors. Subsequent to that report, on October 18, 2011, the NRC approved seven of the Task Force recommendations for implementation. On March 12, 2012, the NRC issued three orders to the U.S. nuclear industry as a result of the Fukushima Dai-ichi event in Japan. The first order requires all domestic nuclear plants to better protect supplemental safety equipment and obtain additional equipment as necessary to protect the reactor in the event of beyond design basis external events. The second order requires nuclear plant operators to add reliable spent fuel pool water level instrumentation. The third order requires nuclear plant operators of boiling water reactors like CNS to add a reliable containment vent, and possibly a filter on the vent.

These actions are to be completed no later than prior to startup from CNS's fall 2016 refueling and maintenance outage or December 31, 2016, whichever comes first. The NRC also issued a request for information to facilitate their determination if there is a need to update the design basis and systems, structures, and operating components important to safety to protect against the updated seismic and flooding hazards at operating reactor sites. Additional NRC orders and regulations resultant from the Fukushima Dai-ichi event are anticipated. The specific impacts of these new recommendations on CNS have not yet been fully evaluated.

In October 2003, the District entered into an agreement (the "Entergy Agreement") for support services at CNS with Entergy Nuclear Nebraska, LLC ("Entergy"), a wholly-owned indirect subsidiary of Entergy Corporation. The Entergy Agreement was for an initial term ending January 18, 2014, subject to either party's right to terminate without cause by providing notice and paying a termination charge. The agreement was subsequently extended, effective January 1, 2010, to January 18, 2029. The Entergy Agreement requires the District to reimburse Entergy's cost of providing services, and to pay Entergy annual management fees. These annual management fees were $17.3 million and $17.2 million for 2011 and 2010, respectively. In 2012, the annual management fee is $17.3 million. Entergy is eligible to earn additional annual incentive fees in an amount not to exceed $4.0 million annually if CNS achieves identified safety and regulatory performance targets. As part of the agreement amendment, the overall compensation to Entergy under the support services agreement was restructured such that certain private use issues that existed with the original agreement were eliminated.

CNS completed construction of a dry cask used fuel storage facility to support planned license renewal. The first loading campaign to move used nuclear fuel from the used fuel pool into eight dry used fuel storage casks for on-site storage commenced in October 2010 and was completed in January 2011.

On November 29, 2010, the NRC formally issued a certificate to the District to commemorate the renewal of the operating license for CNS for an additional 20 years until January 18, 2034. The issuance of this certificate by the NRC marked the culmination of the six-year effort to reach this milestone.

As part of a 1989 settlement of various disputed matters between General Electric Company ("GE") and the District, GE has agreed to continue to store at the Morris Facility the spent nuclear fuel assemblies from the first two full core loadings at CNS at no additional cost to the District until the expiration of the current NRC license in May 2022 for the Morris Facility. After that date, storage would continue to be at no cost to the District as long as GE can maintain the NRC license for the Morris Facility on essentially the existing design and operating configuration.

As a result of the failure of the Department of Energy ("DOE") to dispose of spent nuclear fuel from CNS as required by contract, the District commenced legal action against the DOE on March 2, 2001. On March 17, 2011, the District offered to settle its litigation against the DOE for spent nuclear fuel disposal damages in exchange for the payment of $60.6 million representing costs incurred for the on-site storage of spent nuclear fuel at CNS through December 31, 2009, along with subsequent claims pursuant to the provisions of the settlement agreement. On June 17, 2011, in accordance with the settlement agreement between the District and the DOE, the District received $60.6 million from the DOE for damages through 2009. The District received a second payment from the DOE in the amount of $10.3 million on October 21, 2011 for its subsequent claim submittal to recover the District's costs incurred in 2010. The settlement agreement addresses future claims through 2013. A corresponding deferred credit for these DOE receipts has been established in Other of the Deferred Credits and Other Liabilities section of the accompanying Balance Sheets. The District plans to use the funds to pay for future costs related to CNS.

E. Environmental -

As part of Environmental Protection Agency's ("EPA") nationwide investigation and enforcement program for coal-fired power plants' compliance with Clean Air Act including new source review requirements, on December 4, 2002, the Region 7 office of the EPA sent a letter to the District and three other electric utilities pursuant to Section 114(a) of the Federal Clean Air Act requesting documents and information pertaining to GGS and Sheldon. On April 10, 2003, Region 7 of the EPA sent a supplemental request for documents and information to the District and the other three electric utilities. These EPA requests for information are part of an EPA investigation to determine the Clean Air Act compliance status of GGS and Sheldon, including the potential application of new source review requirements. The District provided the documents and information requested to the EPA within the time allowed. As a supplement to the 2002 and 2003 requests, EPA Region 7 sent another letter to the District on November 8, 2007, requesting additional documents and information pertaining to GGS and Sheldon. The District provided a response to the new request within the time allowed and provided supplemental information to the EPA in February and April 2011 in response to an EPA e-mail inquiry. In a transmittal letter dated December 8, 2008, EPA Region 7 issued a Notice of Violation under Section 113(a)(1) of the Clean Air Act ("NOV") alleging violations of pre-construction permitting requirements of the Clean Air Act and the Nebraska State Implementation Plan for five projects undertaken from 1991 through 2001 at GGS. Since receiving the NOV, the District has met twice with the government to discuss the NOV and possible future actions. No further meetings are scheduled. In the event the government pursues litigation based on the NOV and there is a court judgment finding the District violated Clean Air Act requirements, if upheld after appellate court review, it can result in the requirement to install expensive air pollution control equipment that is the best available control technology and the imposition of monetary penalties. The District is unable to predict what future costs may be incurred with respect to the NOV.

On March 16, 2011, the EPA issued a proposed rule intended to reduce emissions of toxic air pollutants from power plants. The final rule was released by the EPA on December 21, 2011 ("Mercury and Air Toxics Standard Rule"). Specifically, the Mercury and Air Toxics Standard Rule will require reductions in emissions from new and existing coal- and oil-fired steam utility electric generating units of heavy metals, including mercury, arsenic, chromium, and nickel, dioxins, furans, and acid gases, including hydrogen chloride and hydrogen fluoride. These toxic air pollutants are also known as hazardous air pollutants. Facilities will have three years after the Mercury and Air Toxics Standard Rule becomes effective in early 2012 to comply with the rule. Upon request, an additional one-year extension for compliance could possibly be granted if technology necessary to reduce the emissions cannot be installed within the three years. The District expects to meet the new emissions limits with its existing pollution control equipment and the installation of activated carbon injection equipment at GGS and Sheldon. Capital costs for such equipment are estimated to be between $15.0 million and $20.0 million with annual operation and maintenance costs estimated to be between $5.0 million and $7.5 million.

Any changes in the environmental regulatory requirements imposed by federal or state law which are applicable to the District's generating stations could result in increased capital and operating costs being incurred by the District. The District is unable to predict whether any changes will be made to current environmental regulatory requirements, if such changes will be applicable to the District and the costs thereof to the District.

On August 19, 2002, the District received notice from the EPA identifying the District as a Potentially Responsible Party ("PRP") for liability associated with a former Manufactured Gas Plant ("MGP") located in Norfolk, Nebraska. The District is identified as a current owner of property located adjacent to the Norfolk MGP operations. In 2002, the EPA asked identified PRPs to participate in negotiations for completing an Engineering Evaluation/Cost Analysis ("EE/CA"). The identified PRPs met with the EPA Region 7 in October 2002

to discuss the site. No other activities between the District and the EPA had taken place related to this site from the time of the October 2002 meeting with the EPA until June 2004. On June 14, 2004, PRPs received notice from the EPA that the EPA was interested again in beginning efforts to complete an EE/CA to address this site. The District has denied that it has any liability as related to the MGP operations, but has indicated to the EPA willingness to cooperate with efforts to address the site. The District has reached an agreement in principal with the other PRPs to resolve its potential liability for the EE/CA by entering into a settlement agreement under which the District would contribute 10% of the costs of the EE/CA. The settlement agreement for the EE/CA has been signed by all parties and was ratified at the February 2007 Board of Directors meeting. Phase I of the EE/CA work began at the site in November 2007. The current schedule indicates that the EE/CA should be completed in 2012. The District is unable to predict what future costs may be incurred with respect to MGP.

F. Other -

In connection with an examination by the Internal Revenue Service (the "Service") of the District's General Revenue Bonds, 2009 Series A (Taxable Build America Bonds), representatives of the Service verbally expressed the view to the District on February 1, 2012, that approximately $10.0 million principal amount of the bonds maturing on January 1, 2035, may not qualify for the 35% interest subsidy provided by the United States Treasury based on the interpretation by the Service of the issue price of the bonds to the public. The District does not agree with the Service's position and may contest any formal action taken by the Service. It is estimated that the 35% interest subsidy on the $10.0 million of bonds is approximately $260,000 per year. Any loss of such subsidy could be retroactive to the date of issuance of the bonds (June 24, 2009) and could total approximately $6.5 million over the stated term of the bonds.

18. LITIGATION:

A number of other claims and suits are pending against the District for alleged damages to persons and property and for other alleged liabilities arising out of matters usually incidental to the operation of a utility, such as the District. In the opinion of management, based upon the advice of its General Counsel, the aggregate amounts recoverable from the District, taking into account estimated amounts provided in the financial statements and insurance coverage, are not material as of December 31, 2011.

19. SUBSEQUENT EVENT:

In February 2012, the District issued General Revenue Bonds, 2012 Series A, in the amount of $212.4 million to finance $40.3 million of the costs of certain generation and transmission capital additions, to refund $20.2 million of the TERCA indebtedness, and to advance refund a portion of the outstanding 2003 Series A Bonds. With respect to the refunded portion, net proceeds of $177.9 million (after payment of $0.9 million in underwriting fees and other issuance cost) plus an additional $1.4 million of debt service monies were used to purchase U.S. Government securities. Those securities were deposited in an irrevocable trust with an escrow agent to provide for all future debt service payments of the refunded portion of the 2003 Series A Bonds. As a result, the 2014 - 2034 maturities of the 2003 Series A Bonds are considered to be defeased and the liability for these bonds has been removed from the District's balance sheet as of February 29, 2012. The District advance refunded a portion of the 2003 Series A Bonds to reduce its anticipated total debt service payments over the next 23 years by $27.1 million.

Nebraska Public Power District

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