BLACK HILLS CORP /SD/
Form 10-K/A
August 07, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K/A
(Amendment No. 1)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________________ to __________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	625 Ninth Street Rapid City, South Dakota 57701	IRS Identification Number 46-0458824

Registrant's telephone number, including area code
(605) 721-1700
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes x No o

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes o No x

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2014 $2,696,775,649

Indicate the number of shares outstanding of each of the Registrant’s classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2015	
Common stock, $1.00 par value	44,676,072	shares

Documents Incorporated by Reference

Portions of the Registrant’s Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2015 Annual Meeting of Stockholders to be held on April 28, 2015, are incorporated by reference in Part III of this Form 10-K.

Explanatory Note

This Amendment No. 1 (this “Amendment”) amends the Annual Report on Form 10-K for the annual period ended December 31, 2014 originally filed by Black Hills Corporation on February 25, 2015 (the “Original Filing”).

In preparing our consolidated financial statements for the quarter ended June 30, 2015, we identified immaterial errors that impacted our previously issued consolidated financial statements. The prior period errors originated in the year ended December 31, 2008 and related to our oil and gas full cost ceiling impairment calculation to determine whether the net book value of the our oil and gas properties exceeded the ceiling. Specifically, the errors related to evaluating and correctly accounting for the treatment of tax related amounts associated with the calculation. The original errors identified caused an understatement of 2008, 2009, 2012 and Q1 2015 noncash ceiling test impairment calculations, which resulted in an overstatement of depletion expense from 2009 through March 31, 2015, and an understatement of the 2012 gain on sale of oil and gas properties, further described in Note 1 to the consolidated financial statements filed in this Annual Report on Form 10-K/A.

As a result of these immaterial errors, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we re-evaluated the effectiveness of the Company’s internal control over financial reporting as of December 31, 2014, using the criteria in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on this re-evaluation, we have determined that a material weakness in internal control over financial reporting relating to our oil and gas full-cost ceiling, non-cash impairment calculation existed as of December 31, 2014. As a result, we have revised Management’s Report on Internal Control Over Financial Reporting for the year ended December 31, 2014, included herein.

Notwithstanding the material weakness described above, we have concluded that our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2014 as previously filed with the Securities and Exchange Commission (“SEC”), are fairly stated in all material respects in accordance with generally accepted accounting principles in the United States of America for each of the periods presented and that they may still be relied upon. Given this Amendment, we have revised our previously issued consolidated financial statements for the effects of immaterial errors included in this Annual Report on Form 10-K/A for the year ended December 31, 2014.

The following items have been amended as a result of the revision of Management’s Report on Internal Control Over Financial Reporting and to correct immaterial errors:

- Item 6 - Selected Financial Data
- Item 7 - Management’s Discussion and Analysis of Financial Condition and Results of Operations
- Item 8 - Financial Statements and Supplementary Data
- Item 9A - Controls and Procedures
- Item 15 - Exhibits

In accordance with applicable SEC rules, this Annual Report on Form 10-K/A includes certifications from our Chief Executive Officer and Chief Financial Officer dated as of the date of this filing.

Except for the impact of the items discussed above, no other changes have been made to the Original Filing. This Annual Report on Form 10-K/A continues to describe conditions as of the date of the Original Filing, and the disclosures contained herein have not been updated to reflect events, results or developments that have occurred after the Original Filing date, or to modify or update those disclosures affected by subsequent events.

Concurrently with the filing of this Annual Report on Form 10-K/A, we are also filing an amendment to our Form 10-Q for the quarterly period ended March 31, 2015.

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

This Form 10-K/A contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in our Original Filing and this Form 10-K/A, including statements contained within Item 1A - Risk Factors.

PART II

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31, (dollars in thousands, except per share amounts)	2014		2013		2012		2011		2010	
Total Assets	$4,245,902		$3,837,936		$3,688,335		$4,053,216		$3,631,412	
Property, Plant and Equipment										
Total property, plant and equipment	$4,563,400		$4,259,445		$3,930,772		$3,724,016		$3,353,509	
Accumulated depreciation and depletion	$(1,357,929)		$(1,306,390)		$(1,229,159)		$(1,008,307)		$(941,872)	
Capital Expenditures	$391,267		$379,534		$347,980		$431,707		$496,990	
Capitalization										
Current maturities of long-term debt	$275,000		$—		$103,973		$2,473		$5,181	
Notes payable	75,000		82,500		277,000		345,000		249,000	
Long-term debt, net of current maturities	1,267,589		1,396,948		938,877		1,280,409		1,186,050	
Common stock equity	1,353,884		1,283,500		1,205,800		1,161,715		1,048,642	
Total capitalization	$2,971,473		$2,762,948		$2,525,650		$2,789,597		$2,488,873	
Capitalization Ratios										
Short-term debt, including current maturities	12 %		3 %		15 %		12 %		10 %	
Long-term debt, net of current maturities	42 %		51 %		37 %		46 %		48 %	
Common stock equity	46 %		46 %		48 %		42 %		42 %	
Total	100 %		100 %		100 %		100 %		100 %	
Total Operating Revenues	$1,393,570		$1,275,852		$1,173,884		$1,272,188		$1,219,691	
Net Income Available for Common Stock										
Utilities	$101,421		$84,841		$79,588		$81,860		$74,563	
Non-regulated Energy	30,443		20,864	(1)	45,637	(1)	4,875		14,410	
Corporate and intersegment eliminations	(975)		12,602	(2)	(15,808)	(2)	(42,361)	(2)	(21,611)	(2)
Income (loss) from continuing operations	130,889		118,307		109,417		44,374		67,362	
Income (loss) from discontinued operations, net of tax [3]	—		(884)		(6,977)		9,365		5,544	
	$130,889		$117,423		$102,440		$53,739		$72,906	

Net income available for common stock

5

SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2014	2013	2012	2011	2010
Dividends Paid on Common Stock	$69,636	$67,587	$65,262	$59,202	$56,467
Common Stock Data[(4)] (in thousands)					
Shares outstanding, average basic	44,394	44,163	43,820	39,864	38,916
Shares outstanding, average diluted	44,598	44,419	44,073	40,081	39,091
Shares outstanding, end of year	44,672	44,499	44,206	43,925	39,269
Earnings (Loss) Per Share of Common Stock (in dollars) [(4)]					
Basic earnings (loss) per average share -					
Continuing operations	$2.95	$2.68	$2.50	$1.11	$1.73
Discontinued operations	—	(0.02)	(0.16)	0.24	0.14
Total	$2.95	$2.66	$2.34	$1.35	$1.87
Diluted earnings (loss) per average share -					
Continuing operations	$2.93	$2.66	$2.48	$1.11	$1.73
Discontinued operations	—	(0.02)	(0.16)	0.23	0.14
Non-controlling interest	—	—	—	—	—
Total	$2.93	$2.64	$2.32	$1.34	$1.87
Dividends Declared per Share	$1.56	$1.52	$1.48	$1.46	$1.44
Book Value Per Share, End of Year	$30.31	$28.84	$27.28	$26.45	$26.70
Return on Average Common Stock Equity (full year)	9.9 %	9.4 %	8.7 %	4.9 %	6.8 %

6

SELECTED FINANCIAL DATA continued

Years ended December 31,	2014	2013	2012	2011	2010
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	841	790	859	865	687
Electric Utilities (purchased capacity)	210	150	150	450	440
Power Generation (owned generation)	269	309	309	309	120
Total generating capacity	1,320	1,249	1,318	1,624	1,247
Electric Utilities:					
MWh sold:					
Retail electric	4,775,808	4,642,254	4,598,080	4,590,800	4,532,191
Contracted wholesale	340,871	357,193	340,036	349,520	468,782
Wholesale off-system	1,118,641	1,456,762	1,652,949	1,788,005	1,749,524
Total MWh sold	6,235,320	6,456,209	6,591,065	6,728,325	6,750,497
Gas Utilities: (5)					
Gas sold (Dth)	60,323,416	59,097,493	47,358,505	55,764,154	55,265,630
Transport volumes (Dth)	67,463,143	63,821,546	60,480,822	59,216,132	59,879,450
Power Generation Segment:					
MWh Sold	1,760,160	1,564,789	1,304,637	556,577	519,057
MWh Purchased	38,237	5,481	8,011	402	27,734
Oil and Gas Segment:					
Oil and gas production sold (MMcfe)	9,986	9,529	12,544	11,762	11,300
Oil and gas reserves (MMcfe) (1)	101,416	86,713	80,683	133,242	131,096
Coal Mining Segment:					
Tons of coal sold (thousands of tons) (6)	4,317	4,285	4,246	5,692	5,931
Coal reserves (thousands of tons)	208,231	212,595	232,265	256,170	261,860

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(1) 2013 includes $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming’s project financing and write-off of deferred financing costs. 2012 includes a non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties of $32 million offset by an after-tax gain on sale of $49 million related to our Williston Basin assets. Reserves reflect the sale of the Williston Basin assets (see Notes 12 and 21 of the Notes to the Consolidated Financial Statements of this Annual Report on Form 10-K/A).

(2) 2011 and 2010 include a $27 million and $9.9 million non-cash after-tax unrealized mark-to-market loss, respectively, related to certain interest rate swaps; while 2013 and 2012 include a $20 million and $1.2 million non-cash after-tax unrealized mark-to-market gain, respectively, related to certain interest rate swaps. 2013 also includes $7.6 million after-tax expense for a make-whole premium, write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt, while 2012 includes an after-tax make-whole provision of $4.6 million for early redemption of our $225 million notes.

(3) Discontinued operations include post-closing adjustments and operations relating to our Energy Marketing segment in 2013, 2012, 2011 and 2010.

(4) During November 2011, we issued 4.4 million shares of common stock, which diluted our earnings per share in subsequent periods.

(5) Excludes Cheyenne Light.

(6) Tons of coal decreased in 2012 due to the expiration of an unprofitable train load-out contract.

	December 31, 2014			December 31, 2013		
(in thousands, except per share and percentages)	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
Net Income Available for Common Stock						
Non-regulated Energy (in thousands)	$28,335	$2,108	$30,443	$18,403	$2,461	$20,864

7

	December 31, 2012		
(in thousands, except per share and percentages)	As Reported	Adjustments	As Revised
Total Assets	$3,729,471	$(41,136)	$3,688,335
Property, Plant and Equipment			
Accumulated depreciation and depletion	$(1,188,023)	$(41,136)	$(1,229,159)
Common stock equity	$1,232,509	$(26,709)	$1,205,800
Net Income Available for Common Stock			
Non-regulated Energy	$24,725	$20,912	$45,637

	December 31, 2011			December 31, 2010		
(in thousands, except per share and percentages)	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
Total Assets	$4,127,083	$(73,867)	$4,053,216	$3,711,509	$(80,097)	$3,631,412
Property, Plant and Equipment						
Accumulated depreciation and depletion	$(934,441)	$(73,866)	$(1,008,307)	$(861,775)	$(80,097)	$(941,872)
Common stock equity	$1,209,336	$(47,621)	$1,161,715	$1,100,270	$(51,628)	$1,048,642
Net Income Available for Common Stock						
Non-regulated Energy	$866	$4,009	$4,875	$10,189	$4,221	$14,410
Earnings (Loss) Per Share of Common Stock						
Basic earnings (loss) per share per average share -						
Continuing Operations	$1.01	$0.10	$1.11	$1.62	$0.11	$1.73
Discontinued Operations	$0.24	$—	$0.24	$0.14	$—	$0.14
Total	$1.25	$0.10	$1.35	$1.76	$0.11	$1.87
Diluted earnings (loss) per share per average share -						
Continuing Operations	$1.01	$0.10	$1.11	$1.62	$0.11	$1.73
Discontinued Operations	$0.23	$—	$0.23	$0.14	$—	$0.14
Total	$1.24	$0.10	$1.34	$1.76	$0.11	$1.87

For additional information on our business segments see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note 4 to the Consolidated Financial Statements in this Annual Report on Form 10-K/A.

ITEMS 7 & and 7A. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a customer-focused integrated energy company operating principally in the United States with two major business groups - Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Power Generation
	Coal Mining
	Oil and Gas

Overview: Our customer focus provides opportunities to expand our business by constructing additional rate base assets to serve our utility customers and expanding our non-regulated energy products and services to our wholesale customers.

The diversity of our energy operations reduces reliance on any single business segment to achieve our strategic objectives. Our emphasis on our utility business with diverse geography and fuel mix, combined with a conservative approach to our non-regulated energy operations, mitigates our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long-term. Our long-term strategy focuses on growing both our utility and non-regulated energy businesses, primarily by increasing our customer base and providing superior service.

Our objective is to be best-in-class relative to certain operational performance metrics, such as safety, power plant availability, electric and gas system reliability, efficiency, customer service and cost management. Our notable operational performance metrics for 2014 include:

- Our three electric utilities achieved 1st quartile reliability ranking with 74 customer minutes of outage time (SAIDI) in 2014 compared to industry averages (IEEE 2013 1st quartile is less than 85 minutes);
- Our JD Power Customer Satisfaction Survey indicated our Electric and Gas Utilities were favorable to our peers in the Midwest;
- Our power generation fleet achieved a forced outage factor of 2.7% for coal-fired plants, 2.8% for natural gas plants in 2014 and 0.1% for diesel plants, compared to an industry average* of 3.5%, 4.6% and 1.7%, respectively (*NERC GADS 2013 data);
- Our power generation fleet availability was 94% for coal-fired plants, 95% for gas-fired plants, 96% for diesel-fired plants and 99% for wind generation in 2014 while the industry averages^ were 90%, 90%, 96% and 96%, respectively (^NERC GADS Data Base, 2013 most recent industry information);
- Our safety TCIR of 2.0 compares well to an industry average of 2.8* and our DART rate of 1.1 compares to an industry average of 1.4+ (+ Most recent industry averages are 2012);
- Our OSHA TCIR rate during construction of our generating facilities is also significantly better than industry average with a TCIR rate of 2 during the construction of the Wygen III coal-fired plant compared to an industry average of 5.1 for coal-fired plants, 1.3 during the construction of the Pueblo Airport Generating Station natural-gas fired plant compared to an industry average of 4.4 for natural-gas fired plants, 0 during construction of the Busch Ranch wind farm compared to an industry average of 4.4 for wind construction and 0 during the construction of the Cheyenne Prairie Generating Station natural-gas fired plant compared to an industry average of 2.1 for fossil fuel electric power generation; and
- Our coal mine completed three years with favorable MSHA safety results compared to other mines located in the Powder River Basin and received an award from the State of Wyoming for five years without a lost time accident.

The electric utility industry is facing requirements to upgrade aging infrastructure, deploy smart grid technology and comply with new state and federal environmental regulations and renewable portfolio standards. Increased energy efficiency, and smart grid technologies suppress demand in many areas of the United States. These competing considerations present challenges to energy companies’ approach of balancing capital spending and obtaining satisfactory rate recovery on investments.

State regulatory commissions have lowered authorized returns and implemented other regulatory mechanisms for cost recovery due to the slow-growing economy and concerns that utility rate increases may further harm local economies. The average awarded return on equity for investor-owned utilities over the past year has been averaging around 10%. The average regulatory lag is less than 12 months, according to the Edison Electric Institute. Falling interest rates account for much of the lower rates of return, along with actions by state commissions to moderate rate increases during a period of economic recovery.

In our gas and electric utilities’ service territories, we will continue to work with regulators to ensure we meet our obligations to serve projected customer demand and to comply with environmental mandates by constructing the infrastructure necessary to provide safe, reliable energy. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery that provides fair economic returns on our utility investments.

The proliferation of domestic crude oil and natural gas production from shale plays in recent years has provided the domestic market an abundant new supply of both commodities, which has decreased the dependence on foreign resources of these commodities. The increased worldwide supply of crude oil caused WTI prices to decline from June 2014 highs of over $105 per Bbl, to January 2015 lows in the mid-$40s per Bbl. Natural gas prices have fallen from NYMEX prices exceeding $8.00 per MMbtu in February 2014 to below $3.00 per MMbtu in January 2015. Crude oil and natural gas prices are very difficult to predict. We will continue to evaluate the economics for oil or gas projects and investments to exceed our cost of capital. We strive to maintain strong relationships with mineral owners, landowners and regulatory authorities. As prudent, we will continue to grow and develop our existing inventory of crude oil and natural gas reserves. We intend to focus our near-term efforts on proving up the substantial Mancos shale gas potential of our Piceance Basin properties. Given increased regulatory emphasis on wind and solar power resources and environmental regulations and legislation that will limit construction of new coal-fired power plants, we believe that natural gas will be the fuel of choice for power generation. Additional gas-fired peaking resources will also be required to provide critical back-up for renewable technologies.

Currently approximately 40% of electricity generated in the United States is from coal-fired power plants. It will take significant time and expense before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation’s electric supply for the foreseeable future. The current regulatory climate, combined with the EPA's proposed and expected GHG regulations, have limited construction of new conventional coal-fired power plants, but, if technologies such as carbon capture and sequestration become more proven and less expensive, they could provide for the long-term economic use of coal. We have investigated and will continue to investigate the possible deployment of these technologies at our mine site in Wyoming.

We have expertise in permitting, constructing and operating power generation facilities. These skills, combined with our understanding of electric resource planning and regulatory procedures, provide a significant opportunity for us to add long-term shareholder value. We intend to grow our non-regulated power generation business by continuing to focus on long-term contractual relationships with our affiliates and other load-serving utilities.

Key Elements of our Business Strategy

Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities. Our Company began as a vertically-integrated electric utility. This business model remains a core strength and strategy today, as we invest in and operate efficient power generation resources to cost effectively transmit and distribute electricity to our customers. We strive to provide power at reasonable rates to our customers and earn competitive returns for our investors.

We have a competitive power production strategy focused on low cost construction and operation of our generating facilities. Access to our own coal and third-party natural gas reserves allows us to be competitive as a power generator. Low production costs can result from a variety of factors including low fuel costs, efficiency in converting fuel into energy and low per unit operation and maintenance costs. We leverage our mine-mouth coal-fired generating capacity which strengthens our position as a low-cost producer by eliminating fuel transportation costs which often represent the largest component of the delivered cost of coal for many other utilities. In addition, we typically operate our plants with high levels of availability, compared to industry benchmarks. We aggressively manage each of these factors with the goal of achieving low production costs.

Rate-base generation assets offer several advantages including:

- Since the generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run, than if the power was purchased from the open market through wholesale contracts that are re-priced over time;
- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;
- Investors are provided a long-term, reasonable, stable return on their investment; and
- The lower risk profile of rate based generation assets may enhance credit ratings which, in turn, can benefit both consumers and investors by lowering our cost of capital.

Our actions to provide power at reasonable rates to our customers was exemplified in our successful request to secure the construction financing riders in Wyoming and South Dakota during the construction of Cheyenne Prairie. These riders reduced the total cost of the plant ultimately passed along to our customers while we constructed this plant to accommodate growth and replace plants that were closed prematurely due to environmental regulations.

Provide stable long-term rates for customers and increase earnings by efficiently planning and implementing a cost of service gas program to serve our electric and natural gas utilities. To further enhance our vertically integrated utility business model, we are evaluating the implementation of a program supporting our natural gas and electric utilities that can provide longer-term rate stability for our customers by enhancing our current gas supply portfolio through the addition of utility or affiliate-owned gas production and reserves. In addition to providing our customers the benefits associated with more predictable long-term commodity prices, it also provides increased earnings opportunity for our shareholders. We are discussing the concept with state regulatory commissioners, staff and consumer advocates. Prior to proceeding, we will need to obtain regulatory approval from our state utility commissions for the program. Several utilities have cost of service gas programs in place in various states, including both Wyoming and Montana.

We have a competitive advantage related to cost of service gas in that our existing non-regulated oil and gas subsidiary could assist in drilling/acquiring and operating the gas reserves required to meet the needs of our electric and gas utilities.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For more than 130 years we have provided reliable utility services, delivering quality and value to our customers. Utility operations contribute substantially to the stability of our long-term cash flows, earnings and dividend policy. Our tradition of accomplishment supports efforts to expand our utility operations into other markets, most likely in areas that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service, community involvement and a relationship-based approach to regulatory matters. Utility operations also enhance other important business development opportunities, including gas transmission pipelines and storage infrastructure, which could promote other non-regulated energy operations.

We have and will continue to pursue the purchase of not only large utility properties, but also smaller, private or municipal utility systems, which can be easily integrated into our operations. We purchased several small natural gas distribution systems in Kansas, Iowa and Wyoming in the past several years. We have a scalable platform of systems and processes, which simplifies the integration of our utility acquisitions. Merger and acquisition activity has continued in the utility industry and we expect to consider such opportunities if they advance our long-term strategy and add shareholder value.

Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation business. We strive to build strong relationships with other utilities, municipalities and wholesale customers. We believe we will continue to be a primary provider of electricity to wholesale utility customers, who will continue to need products, such as capacity, in order to reliably serve their customers. By providing these products under long-term contracts, we help our customers meet their energy needs. We also earn more stable revenues and greater returns over the long term than we could by selling energy into more volatile spot markets. In addition, relationships that we have established with wholesale power customers have developed into other opportunities. MEAN, MDU and the City of Gillette, Wyoming were wholesale power customers that are now joint owners in two of our power plants, Wygen I and Wygen III.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating and remaining mindful of customer rate impacts. The energy and utility industries face tremendous uncertainty related to the potential impact of legislation and regulation intended to reduce GHG emissions and increase the use of renewable and other alternative energy sources. To date, many states have enacted and others are considering some form of mandatory renewable energy standard, requiring utilities to meet certain thresholds of renewable energy generation. Some states have either enacted or are considering legislation setting GHG emissions reduction targets. Federal legislation for both renewable energy standards and GHG emission reductions is also under consideration.

Mandates for the use of renewable energy or the reduction of GHG emissions will likely produce substantial increases in the prices for electricity and natural gas. At the same time, as a regulated utility we are responsible for providing safe, reasonably priced, reliable sources of energy to our customers. As a result, we employ a customer-centered strategy for complying with renewable energy standards and GHG emission regulations that balances our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.

Colorado legislative mandates apply to our electric utility segment regarding the use of renewable energy. Therefore, we pursue cost-effective initiatives that allow us to meet our renewable energy requirements. Where permitted, we seek to construct renewable generation resources as rate base assets, which helps mitigate the long-term customer rate

- impact of adding renewable energy supplies. For example, the Busch Ranch Wind site, a 29 MW wind turbine project, was completed in the fourth quarter of 2012, as part of our plan to meet Colorado's Renewable Energy Standard. This site also has expansion potential;

- In states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have proactively integrated cost-effective renewable energy into our generation supply based upon our expectation that there will be mandatory renewable energy standards in the future. For example, under two 20-year PPAs we purchase a total of 60 MW of wind energy from wind farms located near Cheyenne, Wyoming for use at Black Hills Power and Cheyenne Light; and

- In all states in which we conduct electric utility operations, we are exploring other cost-effective potential biomass, solar and wind energy projects, particularly wind generation sites located near our utility service territories.

Increase the value of our oil and gas properties by prudently growing our reserves and increasing our production of natural gas and crude oil. Our strategy is to cost-effectively grow our reserves and increase our production of natural gas and crude oil through both organic growth and acquisitions. While consistent growth remains our objective, we emphasize managing for value creation over managing for growth as follows:

- Perform detailed reservoir analysis and apply proven technologies to our existing assets to maximize value;
- Participate in a limited number of selective and meaningful exploration prospects;
- Focus primarily on the Rocky Mountain region, where we can more easily integrate new opportunities with our existing crude oil and natural gas operations as well as our power generation activities. Specifically, we intend to focus our near term efforts on fully developing the substantial shale gas potential of our San Juan and Piceance Basin properties and participating in select oil exploration prospects with substantial upside opportunities;
- Support the future capital requirements of our drilling program by stabilizing cash flows with a hedging program that mitigates commodity price risk for up to three years of future production; and
- Enhance our crude oil and natural gas production activities with the construction or acquisition of mid-stream gathering, compression and treating facilities in a manner that maximizes the economic value of our operations.

Selectively grow our non-regulated power generation business in targeted regional markets by developing assets and selling most of the capacity and energy production through mid- and long-term contracts primarily to load-serving utilities. While much of our recent power plant development has been for our regulated utilities, we seek to expand our non-regulated power generation business by developing and operating power plants in regional markets based on prevailing supply and demand fundamentals, in a manner that complements our existing fuel assets and marketing capabilities. We seek to grow this business through the development of new power generation facilities and disciplined acquisitions primarily in the western region, where we believe our detailed knowledge of market and electric transmission fundamentals provides us a competitive advantage and, consequently, increases our ability to earn attractive returns. We prioritize small-scale facilities that serve incremental growth or provide critical back up to renewable resources and are typically easier to permit and construct than large-scale generation projects.

Most of the energy and capacity from our non-regulated power facilities is sold under mid- and long-term contracts. When possible, we structure long-term contracts as tolling arrangements, whereby the contract counterparty assumes the fuel risk. Going forward, we will continue to focus on selling a majority of our non-regulated capacity and energy primarily to load-serving utilities under long-term agreements that have been reviewed or approved by state utility commissions. An example of this strategy is the 200 MW of combined-cycle gas-fired generation constructed by our non-regulated power generation subsidiary to serve our Colorado Electric utility subsidiary. The plant commenced operations on January 1, 2012, under a 20-year tolling agreement.

Diligently manage the credit, price and operational risks inherent in buying and selling energy commodities. All of our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diverse group of creditworthy counterparties. In certain cases where creditworthiness merits security, we require prepayment, secured letters of credit or other forms of financial collateral. We establish counterparty credit limits and employ continuous credit monitoring, with regular review of compliance under our credit policy by our Executive Risk Committee. Our oil and gas and power generation operations require effective management of price and operational risks related to adverse changes in commodity prices and the volatility and liquidity of the commodity markets. To mitigate these risks, we implemented risk management policies and procedures. Our oversight committees monitor compliance with these policies.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital has been and will continue to be critical to our success. We have demonstrated our ability to access the debt and equity markets, resulting in sufficient liquidity. We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent business growth. Our access to adequate and cost-effective financing depends upon our ability to maintain our investment-grade issuer credit rating.

Moody's and Fitch each upgraded our corporate credit rating during 2014, which enhanced our capacity to extend our revolving credit facility, and place permanent financing for Cheyenne Prairie through the sale of $160 million of first mortgage bonds in a private placement at favorable terms.

Prospective Information

We expect to generate long-term growth through the expansion of integrated and diverse energy operations. Sustained growth requires continued capital deployment. Our diversified energy portfolio with an emphasis on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from major capital investments at our existing business segments. During 2014, we put permanent financing in place for Cheyenne Prairie and during 2013, we refinanced much of our highest cost debt on favorable terms. Although dependent on market conditions, we are confident in our ability to obtain additional financing, as necessary, to continue our growth plans. We remain focused on prudently managing our operations and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

Utilities Group

Electric Utilities

On October 1, 2014, Black Hills Power and Cheyenne Light placed into commercial service their jointly-owned Cheyenne Prairie generating station, a 132 MW generating facility located in Cheyenne, Wyoming. Cheyenne Prairie was constructed on time and on budget. Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Cheyenne Light and Black Hills Power received approval for increased rates in Wyoming effective October 1, 2014. Black Hills Power also implemented interim rates in South Dakota on October 1, 2014. Hearings for the South Dakota rate case were held on January 27-28, 2015 and the commission's final decision is expected in first quarter 2015.

Residential MWh sold decreased in 2014 due to milder weather resulting from lower cooling degree days. Industrial loads increased primarily at Cheyenne Light and Colorado Electric. Cheyenne Light recorded an all-time peak load of 198 MW in July 2014.

BHC continued its efforts to acquire smaller public and municipal gas distribution systems adjacent to our existing service territories. On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc. for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory. In January 2015, Cheyenne Light also closed on the acquisition of assets serving approximately 400 customers in northeast Wyoming.

Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014.

Colorado Electric received a final order from the CPUC approving a CPCN for the retirement of Pueblo Units #5 and #6, effective December 31, 2013.

Pursuant to prior approved resource plans and pending electric rate increase requests, the Electric Utilities engaged in the following regulatory requests related to construction activities:

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. Approval by the WPSC is anticipated in the second quarter of 2015. Black Hills Power has received approval from the SDPUC for a permit to construct the line.

- On May 5, Colorado Electric issued an all-source generation request, including up to 60 megawatts of eligible renewable energy resources to serve its customers in southern Colorado. Our power generation segment submitted solar and wind bids in response to the request. On December 23, 2014 the independent evaluator submitted a report to the Colorado Public Utilities Commission confirming the ranking of the bids. The report's results indicate that our standalone bids were not among the highest ranked bids. However, two of the highest ranked bids provide an opportunity for Colorado Electric or our power generation segment to be partial or full owners of the facilities. At its deliberation in February 2015, the Commission determined none of the alternatives was acceptable, because of potential short-term rate impacts. The Commission discussed the possibility that Colorado Electric could more economically comply with the renewable energy standard by purchasing renewable energy credits. The purchase of renewable energy credits will be considered in a separate proceeding. After review of the Commission's decision regarding the all source solicitation (which has not yet been issued), Colorado Electric will determine whether to seek reconsideration.

- On December 19, 2014, Colorado Electric received approval from the CPUC for an annual electric revenue increase of $3.1 million with a return on equity of 9.83% and a capital structure of 49.83% equity and 50.17% debt. The CPUC also authorized the implementation of a rider for a return on capital expenditures for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

Gas Utilities

Weather was colder than normal in the first quarter of 2014, which drove an increase in natural gas sales. Our Gas Utilities invested in our gas distribution network and related technology such as advanced metering infrastructure and mobile data terminals. We continually monitor our investments and costs of operations in all states to determine the appropriateness of additional rate case or other rate filings. As part of our growth strategy, we continue to look for opportunities to purchase municipal and privately-owned gas infrastructure and distribution systems. We acquired a small gas system during 2014 with a total of approximately 70 customers.

Non-regulated Energy Group

Power Generation

Black Hills Wyoming closed the sale of its 40 MW CTII natural gas-fired generating unit to the City of Gillette for approximately $22 million, upon expiration of the PPA with Cheyenne Light in August 2014. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through an economy energy PPA. We recognized approximately $0.5 million of margin under the new economy PPA, which became effective in September 2014. We plan to continue evaluating opportunities to bid on the construction of generation resources, both new and existing, for our affiliate electric utilities and other regional electric utilities for their energy and capacity needs.

Coal Mining

Production from the Coal Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production was approximately 4.3 million tons for 2014, which was consistent with 2013. Mining operations moved to an area with lower overburden ratios in 2013, which reduced mining costs, but in 2014, our overburden ratios increased as we mined areas with a higher stripping ratio. Stripping ratios are expected to increase again in 2015 to approximately 1.5 as the areas planned for mining contain higher overburden.

Our strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically our off-site sales have been to consumers within a close proximity to our mine, including off-site sales contracts served by truck. In January 2014, we received State of Wyoming permit approval for Black Hills Power to acquire a stock pile of approximately 75,000 tons of coal near the mine mouth power plants to ensure adequate emergency back-up of coal supply. We continue to pursue new opportunities to market our coal despite limitations inherent to transporting our lower-heat content coal.

Oil and Gas

During 2014, BHEP continued to prove up the value of our existing properties, primarily our Mancos formation shale gas assets in the Piceance and San Juan Basins, while conserving capital and strictly controlling costs. After drilling and completing two Mancos formation exploration wells in the southern Piceance Basin and one exploration well in the San Juan Basin in 2011, the appraisal program was deferred in 2012 due to low natural gas prices. The program continued in 2013 with the drilling of two additional Piceance wells. Three more Piceance wells were drilled in 2014, which will be placed on production during the first quarter of 2015. We plan to continue our efforts in 2015 to prove up the value of our oil and gas properties.

Corporate

Our consolidated interest expense decreased in 2014, primarily due to the refinancing of higher cost debt in 2013 as well as upgrades to our corporate credit ratings by S&P, Moody's and Fitch during 2014 and 2013. We executed a 10-year $525 million note offering in November 2013 at an interest rate of 4.25%, which we used to repay higher cost debt and settle interest rate swaps. Our interest expense was unfavorably impacted in 2013 by costs related to early retirement of $250 million senior unsecured notes due in 2014 and the settlement of interest rate swaps.

A portion of the proceeds from the $525 million notes in late 2013 were used for the termination of the de-designated interest rate swaps, which did not qualify for "hedge accounting" treatment provided by accounting standards for derivatives and hedges. With the termination of these swaps, our income statement will no longer reflect the volatility associated with fluctuations in the fair value of these swaps caused by interest rate changes.

Results of Operations

Executive Summary and Overview

	For the Years Ended December 31,				
	2014	Variance	2013	Variance	2012
	(in thousands)				
Revenue					
Utilities	$1,315,079	$110,082	$1,204,997	$123,950	$1,081,047
Non-regulated Energy	206,030	11,481	194,549	(21,690)	216,239
Inter-company eliminations	(127,539)	(3,845)	(123,694)	(292)	(123,402)
	$1,393,570	$117,718	$1,275,852	$101,968	$1,173,884
Income (loss) from continuing operations					
Electric Utilities	$59,552	$7,418	$52,134	$536	$51,598
Gas Utilities	41,869	9,162	32,707	4,717	27,990
Utilities	101,421	16,580	84,841	5,253	79,588
Power Generation [(a)]	28,516	12,228	16,288	(5,040)	21,328
Coal Mining	10,452	4,125	6,327	701	5,626
Oil and Gas[(b)]	(8,525)	(6,774)	(1,751)	(20,434)	18,683
Non-regulated Energy	30,443	9,579	20,864	(24,773)	45,637
Corporate and Eliminations[(c)(d)(e)]	(975)	(13,577)	12,602	28,410	(15,808)
Income from continuing operations	130,889	12,582	118,307	8,890	109,417
Income (loss) from discontinued operations, net of tax[(f)]	—	884	(884)	6,093	(6,977)
Net income (loss)	$130,889	$13,466	$117,423	$14,983	$102,440

(a) Income (loss) from continuing operations in 2013 includes a $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming’s project financing and write-off of deferred financing costs.

(b) Income (loss) from continuing operations in 2012 includes a $32 million non-cash after-tax ceiling test impairment loss and a $49 million after-tax gain on sale of our Williston Basin assets. See Notes 12 and 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K/A.

(c) Financial results of Enserco, our Energy Marketing segment, have been reclassified as discontinued operations in accordance with GAAP. When preparing this reclassification, certain indirect corporate costs and inter-segment interest expenses previously charged to our Energy Marketing segment could not be reclassified to discontinued operations of $0.6 million for 2012 and accordingly have been presented within Corporate. See Note 21 of the Consolidated Financial Statements in this Annual Report on Form 10-K/A.

(d) 2013 includes a $7.6 million after-tax make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt, while 2012 includes a $4.6 million after-tax make-whole premium for the early redemption of our $225 million notes and a $1.0 million write-off of deferred financing costs relating to early renewal of our Revolving Credit Facility.

(e) 2013 and 2012 include a $20 million and a $1.2 million non-cash after-tax mark-to-market gain, respectively, related to certain interest rate swaps.

(f) Income (loss) from discontinued operations, net of tax includes the activities of Enserco, our Energy Marketing segment. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K/A.

On February 29, 2012, we sold our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. Additionally, the following business group and segment information does not include inter-company eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Per share information references diluted shares unless otherwise noted.

2014 Compared to 2013

Income from continuing operations was $131 million, or $2.93 per share, in 2014 compared to $118 million, or $2.66 per share, in 2013. The 2014 Income from continuing operations did not include any expenses, gains, or losses that we believe are not representative of our core operating performance. The 2013 Income from continuing operations includes a $20 million non-cash after-tax mark-to-market gain on certain interest rate swaps, $6.6 million after-tax interest expense related to the early settlement of interest rate swaps and write-off of deferred financing costs associated with the prepayment of Black Hills Wyoming's project financing and $7.6 million after-tax expense for a make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes.

Net income was $131 million, or $2.93 per share, in 2014 compared to $117 million, or $2.64 per share, in 2013 and includes the same items described above and losses from our Energy Marketing segment sold in February 2012.

Business Group highlights for 2014 include:

Utilities Group

Highlights of the Utilities Group include the following:

- Gas Utilities were favorably impacted by colder than normal weather during the first quarter of 2014, which was 14% colder than normal and 7% colder than the first quarter of 2013. This led to an increase in retail natural gas sold and offset unfavorable weather experienced through the remainder of 2014 when compared to 2013. Our service territories reported colder than normal winter weather as measured by heating degree days, compared to the 30-year average, but not as cold as 2013. Heating degree days for the full year in 2014 were 7% colder than normal but 2% less than the same period in 2013.

- Mild weather was a contributing factor for our Electric Utilities during the year. Weather related demand during the peak summer months was tempered by significantly cooler temperatures within our service territories. Cooling degree days for the full year of 2014 were 29% lower than the same period in the prior year and 12% lower than normal.

- On December 19, 2014, Colorado Electric received approval from the CPUC for an annual electric revenue increase of $3.1 million. The approval also allowed a 9.83% return on equity and a capital structure of 49.83% equity and 50.17% debt. The CPUC also authorized the implementation of a rider for a return on capital expenditures for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

- On December 16, Kansas Gas received approval from the Kansas Corporation Commission to increase annual base revenue by an estimated $5.2 million, effective Jan. 1, 2015.

- On October 1, 2014, Black Hills Power and Cheyenne Light placed into commercial service their jointly-owned Cheyenne Prairie generating station. Cheyenne Prairie is a 132 MW, $222 million natural gas-fired generating facility built to serve Black Hills Power and Cheyenne Light customers. Cheyenne Prairie was constructed on time and on budget. Construction financing costs were recovered through construction financing riders.

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044 and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35%, $12 million pollution control revenue bonds, originally due October 1, 2024.

Black Hills Power and Cheyenne Light each received approval from the WPSC on rate cases associated with Cheyenne Prairie. On August 21, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Black Hills Power of approximately $2.2 million for annual electric revenue, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 53.3% equity and 46.7% debt. On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of $8.4 million and $0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 54% equity and 46% debt.

On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt. Interim rates were implemented on October 1, 2014 when Cheyenne Prairie commenced commercial operations. A final ruling from the SDPUC is expected in the first quarter of 2015.

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. Approval by the WPSC is anticipated in the second quarter of 2015.

On June 30, 2014, Black Hills Power filed an application with the SDPUC, for a permit to construct the South Dakota portion of this line, and received approval on November 6, 2014.

- On May 5, 2014, Colorado Electric issued an all-source generation request, including up to 60 megawatts of eligible renewable energy resources to serve its customers in southern Colorado. Our power generation segment submitted solar and wind bids in response to the request. On December 23, 2014 the independent evaluator submitted a report to the Colorado Public Utilities Commission confirming the ranking of the bids. The report's results indicate that our standalone bids were not among the highest ranked bids. However, two of the highest ranked bids provide an opportunity for Colorado Electric or our power generation segment to be partial or full owners of the facilities. At its deliberation in February 2015, the Commission determined none of the alternatives was acceptable, because of potential short-term rate impacts. The Commission discussed the possibility that Colorado Electric could more economically comply with the renewable energy standard by purchasing renewable energy credits. The purchase of renewable energy credits will be considered in a separate proceeding. After review of the Commission's decision regarding the all source solicitation (which has not yet been issued), Colorado Electric will determine whether to seek reconsideration.

- On April 25, 2014, Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014. The approval includes a return on equity of 10.6% and a capital structure of 54% equity and 46% debt.

- On March 21, 2014, Black Hills Power retired the Ben French, Neil Simpson I and Osage coal-fired power plants. These three plants totaling 81 MW were closed because of federal environmental regulations. These plants were largely replaced by Black Hills Power's share of Cheyenne Prairie.

- On February 25, 2014, the CPUC issued a final order after rehearing, approving a CPCN for the retirement of Pueblo Unit #5 and #6, effective December 31, 2013.

- BHC continued its efforts to acquire smaller public and municipal gas distribution systems adjacent to our existing service territories.

On January 1, 2015, we closed a $6 million transaction to acquire the natural gas utility assets of MGTC, Inc., a northeast Wyoming system serving more than 400 customers. This system will be operated by and consolidated into the results of Cheyenne Light.

On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc. for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory.

During the first quarter of 2014, we acquired an additional gas system in Kansas, adding approximately 70 customers.

Non-regulated Energy Group

- Coal Mining completed negotiations on the coal contract price increase with the third-party operator of the Wyodak plant. The new coal price of $18.25 per ton, an increase of approximately $4.75, was effective July 1, 2014.

- On September 3, 2014, Black Hills Wyoming closed the sale of its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately $22 million, upon expiration on August 31, 2014 of the PPA with

Cheyenne Light. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through ancillary agreements, including an operating agreement and an economy energy PPA. The sale resulted in a deferred gain of $4.9 million which Black Hills Wyoming will recognize equally over the twenty-year term of the operating agreement.

- Our southern Piceance Basin drilling program continued in 2014. During the third quarter, three Mancos Shale wells were drilled, cased and cemented. On March 6, 2014, the Summit Midstream cryogenic gas processing plant with a capacity of 20,000 Mcf per day started serving the company’s gas production in the southern Piceance Basin, including two Mancos Shale wells placed on production during the first quarter.

Corporate Activities

- The company recently announced that Anthony Cleberg, executive vice president and chief financial officer, will retire at the end of March 2015. Richard Kinzley, previously vice president and controller and a 15-year veteran of the company, was appointed senior vice president and chief financial officer, effective January 1, 2015. In addition, the senior leadership team was expanded when Brian Iverson, previously vice president and treasurer and 11-year veteran of the company, was appointed senior vice president regulatory and government affairs and assistant general counsel.

- Consolidated interest expense decreased by approximately $41 million in 2014, compared to 2013, due primarily to the refinancing activities occurring during the fourth quarter of 2013 and the extension of our Revolving Credit Facility under favorable terms on May 29, 2014.

- On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a stable outlook.

- On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options for which the borrowing rates were reduced under the amended agreement.

- On January 30, 2014, Moody’s upgraded the BHC credit rating to Baa1 from Baa2 with a stable outlook.

2013 Compared to 2012

Income from continuing operations was $118 million, or $2.66 per share, in 2013 compared to $109 million, or $2.48 per share, in 2012. The 2013 Income from continuing operations includes a $20 million non-cash after-tax mark-to-market gain on certain interest rate swaps, $6.6 million after-tax interest expense related to the early settlement of interest rate swaps and write-off of deferred financing costs associated with the prepayment of Black Hills Wyoming’s project financing and $7.6 million after-tax expense for a make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt. The 2012 Income from continuing operations includes a $49 million after-tax gain on sale related to the Williston Basin asset sale, a $32 million non-cash after-tax ceiling test impairment, a $1.0 million non-cash after-tax write-off of deferred financing costs related to our previous Revolving Credit Facility, a $4.6 million after-tax make-whole premium for the early redemption of our $225 million corporate notes and a $1.2 million non-cash after-tax mark-to-market gain on certain interest rate swaps.

Net income was $117 million, or $2.64 per share, in 2013 compared to $102 million, or $2.32 per share, in 2012 and includes the same items described above and losses from our Energy Marketing segment sold in February 2012.

Business Group highlights for 2013 included:

Utilities Group

Highlights of the Utilities Group include the following:

- On September 17, 2013, the South Dakota Public Utilities Commission approved a general rate case settlement agreement authorizing an increase for Black Hills Power of $8.8 million, or 6.4%, in annual electric revenues effective June 16, 2013. The settlement agreement was confidential and certain terms were not disclosed.

- On September 17, 2013, the SDPUC approved the construction financing rider in lieu of traditional AFUDC with an effective date of April 1, 2013. The rider allowed Black Hills Power to earn and collect a rate of return during the construction period on its approximately 40% share of the total Cheyenne Prairie project cost that relates to South Dakota customers, while also saving customers money over the long-term. Cheyenne Light and Black Hills Power received approval from the WPSC for a similar construction financing rider in 2012 which allowed Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period on approximately a 60% share of the project costs related to serving Wyoming customers, while also lowering the overall cost of the project to customers.

- Utility results for 2013 were favorably impacted by cold weather while 2012 utility results were unfavorably impacted by warm weather, particularly at the Gas Utilities. Our service territories reported colder winter weather, as measured by heating degree days, compared to the 30-year average and the prior year. Heating degree days for the full year in 2013 were 9% higher than weighted average norms for our Gas Utilities and 25% higher than the same period in 2012.

- During 2013, Cheyenne Light and Black Hills Power commenced construction on Cheyenne Prairie. Project costs for plant construction and associated transmission were estimated at $222 million, of which approximately $156 million was spent as of December 31, 2013.

- In April 2013, Colorado Electric filed an Energy Resource Plan with the CPUC addressing its projected resource requirements through 2019. The resource plan identified a 40 MW, simple-cycle, natural gas-fired turbine as the replacement of W.N. Clark. On January 6, 2014, the CPUC issued its initial written decision approving construction of the turbine.

- On April 15, 2013, the IUB approved a Capital Infrastructure Automatic Adjustment Mechanism effective April 25, 2013, for $0.2 million. This adjustment mechanism requires an annual filing, therefore, subsequent filings will vary in size based on eligible infrastructure replacements and the timing of future general rate case filings.

- On November 25, 2013, the NPSC approved an Infrastructure System Replacement Cost Recovery Charge that provided for an annual revenue increase of $1.4 million.

- On December 31, 2013, Colorado Electric retired W.N. Clark and Pueblo Units #5 and #6. These facilities, and certain Black Hills Power generating facilities, are being permanently retired primarily due to state and federal environmental regulations. The affected plants are listed in the table below with their operations suspension date and their ultimate retirement date:

Plant	Company	MW	Type of Plant	Date Suspended	Actual Retirement Date	Age of Plant (in years)
Osage	Black Hills Power	34.5	Coal	October 1, 2010	March 21, 2014	64

Ben French	Black Hills Power	25.0	Coal	August 31, 2012	March 21, 2014	52
Neil Simpson I	Black Hills Power	21.8	Coal	NA	March 21, 2014	43
W.N. Clark	Colorado Electric	42.0	Coal	December 31, 2012	December 31, 2013	57
Pueblo Unit #5	Colorado Electric	9.0	Gas	December 31, 2012	December 31, 2013	71
Pueblo Unit #6	Colorado Electric	20.0	Gas	December 31, 2012	December 31, 2013	63
	Total MW	152.3				

- Gas Utilities continued efforts to acquire small gas distribution systems adjacent to their existing gas utility service territories. During 2013, five small gas systems with a total of approximately 900 customers were acquired.

Non-regulated Energy Group

Highlights of the Non-regulated Energy Group include the following:

- In 2013, our Oil and Gas segment drilled and completed two horizontal wells in the Mancos Shale formation in the Piceance Basin. These wells are part of a transaction in which we earned approximately 20,000 net acres of Mancos Shale leasehold in the Piceance Basin in exchange for drilling and completing the two wells.

- Black Hills Wyoming entered into an agreement to sell its 40 MW CTII natural-gas fired generating unit to the City of Gillette for approximately $22 million upon expiration on August 31, 2014 of the PPA with Cheyenne Light. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through ancillary agreements, including a 20-year operating agreement and a 20 year economy energy PPA. The sale closed in September 2014.

- On September 27, 2012, our Oil and Gas segment sold approximately 85% of its Williston Basin assets, including approximately 73 gross wells and 28,000 net leasehold acres, for net cash proceeds of approximately $228 million. We recognized a gain of $76 million on the sale. The portion of the sale amount not recognized as gain reduced the full-cost pool and had the effect of reducing the depreciation, depletion and amortization rate after the sale.

- Coal Mining continued operations under its revised mine plan. Mining operations moved in August 2012, to an area with lower overburden ratios, which reduced mining costs in 2013.

- In the second quarter of 2012, our Oil and Gas segment recorded a $50 million non-cash ceiling test impairment loss as a result of continued low natural gas prices.

Corporate

Activities at Corporate include the following:

- On November 19, 2013, we completed a public debt offering of $525 million in senior unsecured debt at 4.25% due November 30, 2023. Proceeds were used to redeem our $250 million, 9% senior unsecured notes, pay off the Black Hills Wyoming project financing and related interest rate swaps, settle the de-designated interest rate swaps, partially pay down our Revolving Credit Facility and the remainder was used for other corporate purposes.

- On September 25, 2013, Moody’s raised our corporate credit rating to Baa2 from Baa3 with continued positive outlook. On July 24, 2013, S&P raised our corporate credit rating to BBB from BBB- with a stable outlook. They also raised our senior unsecured rating to BBB from BBB-. On May 10, 2013, Fitch Ratings raised our Issuer Default Rating to BBB from BBB- with a positive outlook. Subsequently on January 30, 2014, Moody’s upgraded our corporate credit rating to Baa1 and changed their outlook to stable.

- On June 21, 2013, we replaced our $150 million and $100 million term loans with a two-year term loan for $275 million at an interest rate of 1.125% over LIBOR.

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $30 million in 2013 compared to a $1.9 million unrealized mark-to-market loss on these swaps in 2012. These swaps were settled in November 2013.

Operating Results

A discussion of operating results from our business segments follows.

All amounts are presented on a pre-tax basis unless otherwise indicated.

Utilities Group

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors’ understanding of our operating performance.

In our Management Discussion and Analysis of Results of Operations, gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel, purchased power and cost of gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies’ gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue - electric	$657,556	$29,511	$628,045	$32,503	$595,542
Revenue - Cheyenne Light gas	39,754	2,491	37,263	5,839	31,424
Total revenue	697,310	32,002	665,308	38,342	626,966
Fuel and purchased power - electric	291,645	16,682	274,963	17,921	257,042
Purchased gas - Cheyenne Light	22,928	3,843	19,085	2,653	16,432
Total fuel and purchased power	314,573	20,525	294,048	20,574	273,474
Gross margin - electric	365,911	12,829	353,082	14,582	338,500
Gross margin - Cheyenne Light gas	16,826	(1,352)	18,178	3,186	14,992
Total gross margin	382,737	11,477	371,260	17,768	353,492
Operations and maintenance	165,640	5,679	159,961	13,434	146,527
Depreciation and amortization	79,424	1,720	77,704	2,460	75,244
Total operating expenses	245,064	7,399	237,665	15,894	221,771
Operating income	137,673	4,078	133,595	1,874	131,721
Interest expense, net	(48,787)	7,473	(56,260)	(5,219)	(51,041)
Other income, net	1,164	531	633	(549)	1,182
Income tax expense	(30,498)	(4,664)	(25,834)	4,430	(30,264)

Income from continuing operations	$59,552	$7,418	$52,134	$536	$51,598

	2014	2013	2012
Regulated power plant fleet availability:			
Coal-fired plants [(a)]	93.8%	96.7%	90.8%
Other plants [(b)]	90.2%	96.5%	96.9%
Total availability	91.5%	96.6%	93.9%

(a) 2014 reflects a planned overhaul on Neil Simpson II for emissions controls upgrades.
(b) 2014 reflects planned overhauls for control system upgrades to meet NERC cyber security regulations on the Ben French CT's 1-4.

2014 Compared to 2013

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $9.0 million, and increased rider margins from Cheyenne Prairie by $5.5 million. Industrial megawatt hours sold increased by approximately 15%, primarily due to load growth at Cheyenne Light resulting in increased margins of $1.7 million. Facility improvements at one of our large industrial customers drove a $1.8 million increase in technical service revenues. These increases were partially offset by a $3.5 million decrease from lower demand and residential megawatt hours sold driven by a 29% decrease in cooling degree days compared to the same period in the prior year, a $1.6 million decrease from the TCA, and a $0.8 million decrease from a construction savings incentive recognized in the prior year. Our Cheyenne Light gas utility experienced a decrease in heating degree days, resulting in a $1.4 million decrease in retail natural gas sales.

Operations and maintenance increased primarily due to property taxes, regulatory support and legal fees, generation maintenance, and employee costs.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of Cheyenne Prairie.

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013, and extending our revolving credit facility under favorable terms during the second quarter of 2014.

Income tax benefit (expense): The effective tax rate was comparable to the same period in the prior year.

2013 Compared to 2012

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $5.9 million, increased rider margins by $9.4 million and a $2.2 million increase at our gas utility due to an increase in volumes driven by a 17% increase in heating degree days. These are partially offset by a $2.1 million construction savings incentive received by Colorado Electric in 2012 compared to $0.7 million received in 2013.

Operations and maintenance increased primarily due to property taxes, vegetation management and employee costs. Prior year included a $2.1 million reduction of major maintenance accruals related to plant suspensions and retirements.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net increased primarily due to lower AFUDC.

Income tax benefit (expense): The effective tax rate decreased primarily due to an unfavorable income tax true-up adjustment that impacted 2012.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue:					
Natural gas - regulated	$587,378	$77,123	$510,255	$84,987	$425,268
Other - non-regulated	30,390	956	29,434	621	28,813
Total revenue	617,768	78,079	539,689	85,608	454,081
Cost of natural gas sold:					
Natural gas - regulated	365,034	69,609	295,425	64,163	231,262
Other - non-regulated	15,818	780	15,038	951	14,087
Total cost of natural gas sold	380,852	70,389	310,463	65,114	245,349
Gross margin:					
Natural gas - regulated	222,344	7,514	214,830	20,824	194,006
Other - non-regulated	14,572	176	14,396	(330)	14,726
Total gross margin	236,916	7,690	229,226	20,494	208,732
Operations and maintenance	132,635	6,562	126,073	8,683	117,390
Depreciation and amortization	26,499	118	26,381	1,218	25,163
Total operating expenses	159,134	6,680	152,454	9,901	142,553
Operating income	77,782	1,010	76,772	10,593	66,179
Interest expense, net	(15,284)	8,974	(24,258)	(277)	(23,981)
Other expense (income), net	34	94	(60)	(165)	105
Income tax expense	(20,663)	(916)	(19,747)	(5,434)	(14,313)
Income from continuing operations	$41,869	$9,162	$32,707	$4,717	$27,990

2014 Compared to 2013

Gross margin increased primarily due to higher transport volumes which increased transport margins by $1.7 million. Rider margins increased $2.9 million primarily due to additional capital investments, and $1.6 million of additional margin was attributed to year over year customer growth. Higher retail volumes sold, driven mostly by a 7 percent increase in heating degree days realized in the first quarter of 2014 resulted in a $1.2 million increase. Heating degree days for the twelve months ended December 31, 2014, were 2% lower than the same period in the prior year, and 7% higher than normal.

Operations and maintenance increased primarily due to employee costs, property taxes, outside services, and uncollectible accounts attributed to increased revenue.

Depreciation and amortization was comparable to the same period in the prior year.

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013.

Income tax: The effective tax rate for 2014 was lower primarily due to a favorable true-up adjustment to the filed 2013 income tax return, in addition to an increase in flow-through tax adjustments.

2013 Compared to 2012

Gross margin increased primarily due to a $12 million increase resulting from higher retail volumes driven by a 25% increase in heating degree days. Transport margins increased $2.9 million, surcharge revenue increased $1.9 million primarily due to additional capital investments and $1.3 million of additional margin was attributed to year over year customer growth.

Operations and maintenance increased primarily due to employee costs, property taxes and uncollectible accounts attributed to increased revenue.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net was comparable to the same period in the prior year.

Income tax: The effective tax rate for 2013 increased primarily as a result of favorable flow-through tax adjustment that benefited 2012.

Non-regulated Energy Group

Power Generation

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue	$87,558	$4,521	$83,037	$3,648	$79,389
Operations and maintenance	33,126	2,940	30,186	195	29,991
Depreciation and amortization	4,540	(551)	5,091	492	4,599
Total operating expenses	37,666	2,389	35,277	687	34,590
Operating income	49,892	2,132	47,760	2,961	44,799
Interest expense, net	(3,669)	16,724	(20,393)	(5,636)	(14,757)
Other income (expense), net	(6)	(7)	1	(6)	7
Income tax expense	(17,701)	(6,621)	(11,080)	(2,359)	(8,721)
Income from continuing operations	$28,516	$12,228	$16,288	$(5,040)	$21,328

	2014	2013	2012
Contracted fleet plant availability:			
Gas-fired plants	99.0%	99.0%	99.4%
Coal-fired plants [(a)]	94.7%	94.5%	99.6%
Total	97.8%	97.9%	99.4%

(a) Wygen I experienced planned outages in 2014 and 2013.

26

2014 Compared to 2013

Revenue increased primarily due to an increase in megawatt hours delivered at higher prices, an increase in fired hours, and an increase from the new economy energy PPA with the City of Gillette, partially offset by the expiration of the CTII capacity contract with Cheyenne Light.

Operations and maintenance increased primarily due to increased outside services and materials, and additional maintenance costs on the Wygen I outage, partially offset by decreased employee costs.

Depreciation and amortization decreased primarily due to lower depreciation at Black Hills Wyoming. The generating facility located in Pueblo, Colo. is accounted for as a capital lease under GAAP; as such, depreciation expense for the original cost of the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013. The fourth quarter of 2013 included $7.7 million relating to the cost to settle the interest rate swaps associated with Black Hills Wyoming’s project financing and a $2.4 million write-off of related deferred financing costs.

Income tax expense: The effective tax rate was comparable to the same period in the prior year.

2013 Compared to 2012

Revenue increased primarily due to $2.1 million relating to increased MWh delivered at higher prices and $2.3 million related to increased volumes and pricing for off-system sales at Black Hills Wyoming.

Operations and maintenance increased primarily due to two Wygen I outages, partially offset by decreased property taxes at Black Hills Colorado IPP.

Depreciation and amortization were comparable to the same period in the prior year. The generating facility located in Pueblo, Colorado is accounted for as a capital lease under GAAP; as such, depreciation expense for the original cost of the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net increased primarily due to $7.7 million relating to the cost to settle the interest rate swaps associated with Black Hills Wyoming’s project financing and a $2.4 million write-off of related deferred financing costs, partially offset by lower inter-company debt.

Income tax expense: The effective tax rate in 2013 increased as a result of an unfavorable tax true-up adjustment.

Coal Mining

Coal Mining operating results for the years ended December 31 were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue	$63,358	$6,730	$56,628	$(1,150)	$57,778
Operations and maintenance	41,172	1,653	39,519	(3,034)	42,553
Depreciation, depletion and amortization	10,276	(1,247)	11,523	(1,537)	13,060
Total operating expenses	51,448	406	51,042	(4,571)	55,613
Operating income (loss)	11,910	6,324	5,586	3,421	2,165
Interest (expense) income, net	(434)	197	(631)	(1,561)	930
Other income, net	2,275	(29)	2,304	(312)	2,616
Income tax benefit (expense)	(3,299)	(2,367)	(932)	(847)	(85)
Income (loss) from continuing operations	$10,452	$4,125	$6,327	$701	$5,626

The following table provides certain operating statistics for the Coal Mining segment (in thousands):

	2014	2013	2012
Tons of coal sold	4,317	4,285	4,246
Cubic yards of overburden moved	4,646	3,192 (a)	8,329
Coal reserves at year-end	208,231	212,595 (b)	232,265

(a) Reduction in overburden was due to relocating mining operations in the second half of 2012 to an area of the mine with lower overburden.

(b) Reduction in coal reserves was due to revisions in coal modeling based upon engineering data, changes in coal limit boundaries and current coal production.

2014 Compared to 2013

Revenue increased primarily due to an 11% increase in the price per ton sold driven primarily by a coal price increase with the third-party operator of the Wyodak plant. Price per ton also increased as a result of an increase in pricing on contracts containing price adjustments based on actual mining costs. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes. Our mining costs have increased due to higher operations and maintenance costs driven by mining in areas with a higher stripping ratio than the prior year, thereby increasing our price per ton for these customers.

Operations and maintenance increased primarily due to mining in areas with higher overburden, materials and outside services on major maintenance projects, and an increase in royalties and revenue related taxes driven by increased revenue, partially offset by lower employee costs.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets driven by a reduction in equipment run hours from changes in the mine plan design, and lower depreciation of mine reclamation costs.

Interest (expense) income, net is comparable to the same period in the prior year.

Income tax: The effective tax rate in 2014 is higher due to the reduced impact of the tax benefit of percentage depletion.

2013 Compared to 2012

Revenue decreased primarily due to a 9% decrease in the average price per ton charged on coal sold under contracts containing price adjustments, partially offset by a 1% increase in tons sold. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes. Our mining costs have trended down due to lower operations and maintenance costs, thereby decreasing our price per ton for these customers.

Operations and maintenance decreased primarily due to mining in areas with lower overburden, resulting in decreased fuel costs and reduced employee costs, partially offset by materials and outside services related to major maintenance projects.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets and lower depreciation of mine reclamation costs.

Interest (expense) income, net reflects decreased interest income primarily due to a decrease in the inter-company notes receivable, reduced by payment of a dividend to our parent.

Income tax benefit (expense): The effective tax rate increased in 2013 as a result of lower percentage depletion. In addition, the effective tax rate in 2012 was impacted by a favorable true-up adjustment that was primarily driven by an increased percentage depletion deduction reported on the 2011 tax return.

Oil and Gas

Oil and Gas operating results for the years ended December 31 were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue	$55,114	$230	$54,884	$(24,188)	$79,072
Operations and maintenance	42,659	2,294	40,365	(2,902)	43,267
Gain on sale of assets	—	—	—	75,854	(75,854)
Depreciation, depletion and amortization	24,246	6,369	17,877	(11,908)	29,785
Impairment of long-lived assets	—	—	—	(49,571)	49,571
Total operating expenses	66,905	8,663	58,242	11,473	46,769
Operating income (loss)	(11,791)	(8,433)	(3,358)	(35,661)	32,303
Interest expense, net	(1,685)	(1,071)	(614)	3,321	(3,935)
Other income (expense), net	183	75	108	(99)	207
Income tax benefit (expense)	4,768	2,655	2,113	12,005	(9,892)
Income (loss) from continuing operations	$(8,525)	$(6,774)	$(1,751)	$(20,434)	$18,683

The following tables provide certain operating statistics for the Oil and Gas segment:

Crude Oil and Natural Gas Production	2014	2013	2012
Bbls of oil sold	337,196	336,140	559,971
Mcf of natural gas sold	7,155,076	6,983,104	8,686,191
Bbls of NGL sold	134,555	88,205	82,989
Mcf equivalent sales	9,985,584	9,529,178	12,543,948

Average Price Received [(a)]	2014	2013	2012
Gas/Mcf	$2.91	$2.69	$3.33
Oil/Bbl	$79.39	$89.34	$83.27
NGL/Bbl	$35.53	$33.15	$32.41

(a) Net of hedge settlement gains/losses

	2014	2013	2012
Depletion expense/Mcfe*	$1.84	$1.40	$2.11

* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The decreased depletion rate in 2013 is primarily driven by the Williston Basin sale and ceiling test impairment in 2012. See Note 21 of Notes to the Consolidated Financial Statements included in this Annual Report filed on Form 10-K/A.

The following is a summary of certain annual average costs per Mcfe at December 31:

2014	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.52	$1.11	$0.56	$3.19
Piceance	0.31	3.74	0.38	4.43
Powder River	1.77	—	1.26	3.03
Williston	1.46	—	1.24	2.70
All other properties	1.43	—	0.43	1.86
Average	$1.24	$1.37	$0.68	$3.29

2013	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.33	$0.96	$0.45	$2.74
Piceance	0.69	1.68	0.04	2.41
Powder River	1.66	—	1.18	2.84
Williston	1.06	—	1.38	2.44
All other properties	0.86	—	0.18	1.04
Average	$1.22	$0.66	$0.60	$2.48

	2012			
	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.22	$0.71	$0.35	$2.28
Piceance	0.30	1.29	0.17	1.76
Powder River	1.57	—	1.18	2.75
Williston	0.35	—	1.35	1.70
All other properties	1.91	—	0.34	2.25
Average	$1.05	$0.49	$0.64	$2.18

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, and the cost of operating our own gathering systems is included in operations and maintenance. The gathering, compression, processing and transportation costs shown in the tables above include amounts paid to third parties, as well as costs incurred in operations associated with our own gas gathering, compression, processing and transportation.

We revised our presentation of these costs in 2014 to include both third-party costs and operations costs, and have restated the 2013 and 2012 amounts accordingly. Our 2014 amounts were impacted by a ten-year gas gathering and processing contract for natural gas production in our Piceance Basin in Colorado that became effective in 2014. This take or pay contract requires us to pay the fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. In 2014 our delivery of production did not meet the minimum requirement; therefore our cost per Mcfe increased as illustrated in the table above.

The following is a summary of our proved oil and gas reserves at December 31:

	2014	2013	2012
Bbls of oil (in thousands)	4,276	3,921	4,116
MMcf of natural gas	65,440	63,190	55,985
Bbls of NGLs (in thousands) [(a)]	1,720	—	—
Total MMcfe	101,416	86,713	80,683

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(a) NGL reserves for 2013 and 2012 are not available and were included with MMcf of natural gas in 2013 and 2012.

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by CG&A. Reserves were determined using SEC-defined product prices. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The current estimate takes into account 2014 production of approximately 10.0 Bcfe, additions from extensions, discoveries and acquisitions (sales) of 16.2 Bcfe and positive revisions to previous estimates of 8.5 Bcfe, primarily due to oil and natural gas pricing.

Reserves reflect SEC-defined pricing held constant for the life of the reserves, as follows:

	2014		2013		2012	
	Oil	Gas	Oil	Gas	Oil	Gas
NYMEX prices	$94.99	$4.35	$96.94	$3.67	$94.71	$2.76
Well-head reserve prices	$85.80	$3.33	$89.79	$3.45	$85.31	$2.24

2014 Compared to 2013

Revenue increased primarily due to a 5% increase in volumes sold and an 8% increase in average price received for natural gas sold, partially offset by an 11% decrease in the average price received for crude oil sold.

Operations and maintenance increased primarily due to increased employee costs, higher lease operating and field operation expense, and higher production taxes and ad valorem taxes on higher revenue.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate applied to increased production.

Interest expense, net increased primarily due to third-party interest received on non-operated well revenue in the prior year that offset 2013 expense.

Income tax (expense) benefit: Each period presented reflects a tax benefit. The tax benefit for 2014 was impacted by an unfavorable true-up adjustment to the filed 2013 income tax return.

2013 Compared to 2012

Revenue decreased primarily due to a 24% decrease in volumes sold as a result of the sale of our Williston Basin assets in 2012, a natural production decline in our gas wells and a 19% decrease in average price received for natural gas sold, partially offset by a 7% increase in the average price received for crude oil sold.

Operations and maintenance decreased primarily due to lower non-operated well costs and lower production taxes and ad valorem taxes on reduced revenue.

Gain on sale of operating assets represents the gain on the sale of our Williston Basin assets in 2012. We follow the full-cost method of accounting for oil and gas activities, which typically does not allow for gain on sale recognition unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. The remainder of the sale amount not recognized as gain reduced the full-cost pool and had the effect of reducing the depreciation, depletion and amortization rate.

Depreciation, depletion and amortization decreased primarily due to a lower proportion of our total reserves being from crude oil in 2013, resulting from the sale of our Williston Basin assets in 2012.

Impairment of long-lived assets represents a write-down in the value of our natural gas and crude oil properties driven by low natural gas prices in the second quarter of 2012. The write-down reflected a 12-month average NYMEX price of $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead, for natural gas and $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead, for crude oil.

Interest expense, net reflects lower interest expense primarily due to decreased debt as a result of proceeds from the sale of our Williston Basin assets in 2012.

Income tax (benefit) expense: 2013 produced a pre-tax net loss that resulted in an income tax benefit. The impact of the tax benefit from percentage depletion had a greater effect in 2013 when compared to the prior year.

Corporate

Corporate results represent certain unallocated costs for administrative activities that support the business segments. Corporate also includes business development activities that do not fall under the two business groups as well as allocated costs associated with discontinued operations that could not be included in discontinued operations.

2014 Compared to 2013

Loss from continuing operations for the twelve months ended December 31, 2014, was $1 million compared to income from continuing operations of $13 million for the same period in the prior year. Results for the year ended December 31, 2014 increased primarily due to refinancing activity that took place during the fourth quarter of 2013. Results for the twelve months ended December 31, 2013 reflect a $30 million non-cash unrealized mark-to-market gain related to certain interest rate swaps. Corporate results for 2013 also include $10 million of costs related to early retirement of $250 million senior unsecured notes including a make-whole premium, write-off of deferred financing costs and interest expense on new debt.

2013 Compared to 2012

Corporate results for 2013 include costs of $10 million for a make-whole premium and write-off of deferred financing costs related to early retirement of our $250 million senior unsecured notes and interest expenses on new debt, compared to $7.1 million for a make-whole premium related to the early retirement of our $225 million senior unsecured notes in 2012. We also had an unrealized, non-cash mark-to-market gain on certain interest rate swaps of approximately $30 million in 2013, compared to an unrealized, non-cash mark-to-market gain of $1.9 million on these interest rate swaps for the year ended December 31, 2012.

2012 includes costs of $0.9 million previously allocated to our Energy Marketing segment were reclassified to the Corporate activities consistent with accounting for discontinued operations.

Discontinued Operations

On February 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. Net cash proceeds at date of sale were approximately $165 million, subject to final post-closing adjustments.

The buyer asserted certain purchase price adjustments, some that we accepted, and several that we disputed. The disputed claims were substantially resolved through a binding arbitration decision dated January 17, 2014. We expensed an additional $1.1 million in 2013 related to the claims assigned to arbitration from purchase price adjustments we accepted through a partial settlement agreement with the buyer. Loss from discontinued operations was $0.9 million for the twelve months ended December 31, 2013. Results for 2013 include the resolution of all previously unresolved purchase price adjustments.

Critical Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management’s judgment in application. There are also areas which require management’s judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments, or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, “Business Description and Significant Accounting Policies” of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K/A.

Goodwill

We perform our goodwill impairment test as of November 30 each year or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. Our reporting units have been determined to be at the subsidiary level. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount exceeds fair value under the first step, then the second step of the impairment test is performed to measure the amount of any impairment loss.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans with long range cash flows estimated using a terminal value calculation and adjusted as appropriate for our view of market participant assumptions, 2) estimates of long-term growth rates for our businesses, 3) the determination of an appropriate weighted-average cost of capital or discount rate, and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries.

We have $353 million in goodwill as of December 31, 2014. The results of our November 30, 2014, annual impairment test indicated that our goodwill was not impaired, since the estimated fair value of all reporting units exceeded their carrying value.

Although an impairment did not exist as of November 30, 2014, we determined that one reporting unit, Colorado Electric with goodwill of $245 million, had an estimated fair value that exceeded its carrying value by 24%, which we do not consider a substantial excess. The result of our valuation analysis estimates Colorado Electric's fair value at $860 million, compared to a carrying value of $694 million as of November 30, 2014. The result of the income approach was sensitive to the 2% long-term cash flow growth rate applicable to periods beyond our internal five-year business plan financial forecast and the 5.04% weighted-average cost of capital assumptions. As an illustration of this sensitivity, an increase of 0.25% in the cost of capital combined with a growth rate reduction of 0.25% would result in an estimated fair value in excess of carrying value of $99 million, or 14%, as of November 30, 2014.

Full Cost Method of Accounting for Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available - successful efforts and full cost. We account for our oil and gas activities under the full cost method, whereby all productive and nonproductive costs related to acquisition, exploration, development, abandonment and reclamation activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling at June 30, 2012, which required a write-down of $32 million after-tax. We’ve taken no further write-downs related to our oil and gas full-cost pool since then and under the

SEC-defined product prices at December 31, 2014, no write-down was required. Reserves in 2014 and 2013 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Because of the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur. However, if the current low price environment continues, it is probable that we will have an impairment in 2015.

As noted, we utilize the full-cost method of accounting for our oil and gas activities in accordance with SEC Rule 4-10 of Regulation S-X (Rule 4-10). Under the full-cost method, sales of oil and gas properties generally are recorded as an adjustment to capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between the capitalized costs and proved oil and gas reserves. The Company’s sale of oil and gas properties in the Williston Basin of North Dakota in 2012 was significant as defined by Rule 4-10 and, accordingly, a $49 million after-tax gain on sale was recorded. Total net cash proceeds from the sale were approximately $228 million.

Under the guidance of Rule 4-10, if a gain or loss is recognized on such a sale, total capitalized costs shall be allocated between the reserves sold and the reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair value of the properties in the cost center. Because of the substantial differences between the Williston Basin crude oil properties we sold and those properties retained, which were predominantly natural gas, we allocated based on relative fair values.

If a different method of allocating the capitalized costs was chosen, the gain recorded on our transaction could vary substantially. For example, if the allocation was made on the same basis used to compute amortization as noted within Rule 4-10 and we utilized the ratio of proven reserve quantities from the properties sold compared to total proven reserve quantities in our cost center, we would have recorded a gain on sale of approximately $180 million. Because of the value associated with the undeveloped acreage sold, we did not believe this was an appropriate methodology for allocation. If the amount of gain were recorded differently, it would impact the amount of adjustment to our capitalized costs therefore impacting future depletion expense recorded within our consolidated financial statements.

Oil, Natural Gas, and Natural Gas Liquids Reserve Estimates

Estimates of our proved oil, natural gas and NGL reserves are based on the quantities of each that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. An independent petroleum engineering company prepares reports that estimate our proved oil, natural gas and NGL reserves annually. The accuracy of any oil, natural gas and NGL reserve estimate is a function of the quality of available data, engineering judgment and geological interpretation. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and work over costs, all of which may in fact vary considerably from actual results. In addition, as oil, natural gas and NGL prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Despite the inherent imprecision in estimating our oil, natural gas and NGL reserves, the estimates are used throughout our financial statements. For example, since we use the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporates the estimated unit-of-production attributable to the estimates of proved reserves. The net book value of our oil and gas properties is also subject to a “ceiling” limitation based in large part on the value of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Risk Management Activities

In addition to the information provided below, see Note 8, “Risk Management Activities” and Note 9, “Fair Value Measurement,” of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K/A.

Derivatives

Accounting standards for derivatives require the recognition of all derivative instruments as either assets or liabilities on the balance sheet and their measurement at fair value. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or fair values. The effective portion of changes in fair values of derivatives designated as cash flow hedges is recorded as a component of other comprehensive income (loss) until it is reclassified into earnings in the same period that the hedged item is recognized in earnings. The ineffective portion of changes in fair value of derivatives designated as cash flow hedges is recorded in current earnings. Changes in fair value of derivatives designated as fair value hedges are recognized in current earnings along with fair value changes of the underlying hedged item.

We currently use derivative instruments, including options, swaps, and futures, for non-trading (hedging) purposes. Our typical hedging transactions relate to contracts we enter into to fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the natural gas hedging plans for gas and electric utilities and for interest rate swaps we enter into to convert a portion of our variable rate debt, or associated variable rate interest payments, to a fixed rate.

Fair values of derivative instruments contracts are based on actively quoted market prices or other external source pricing information, where possible. If external market prices are not available, fair value is determined based on other relevant factors and pricing models that consider current market and contractual prices for the underlying financial instruments or commodities, as well as time value and yield curve or volatility factors underlying the positions.

Pricing models and their underlying assumptions impact the amount and timing of unrealized gains and losses recorded and the use of different pricing models or assumptions could produce different financial results.

Pension and Other Postretirement Benefits

As described in Note 17 to the Consolidated Financial Statements in this Annual Report on Form 10-K/A, we have two defined benefit pension plans, three defined post-retirement healthcare plans and several non-qualified retirement plans. A Master Trust holds the assets for the Pension Plans. Each Pension Plan has an undivided interest in the Master Trust. Trusts for the funded portion of the post-retirement healthcare plans have also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long-term rates of return on plan assets; rate of future increases in compensation levels; and healthcare cost projections. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The pension benefit cost for 2015 for our non-contributory funded pension plan is expected to be $13.2 million compared to $8.1 million in 2014. The estimated discount rate used to determine annual benefit cost accruals will be 4.20% in 2015; the discount rate used in 2014 was 5.05%. In selecting the discount rate, we consider cash flow durations for each plan’s liabilities and returns on high credit quality fixed income yield curves for comparable durations.

We do not pre-fund our non-qualified pension plans. One of the three postretirement benefit plans is partially funded. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our three Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2014 Accumulated Postretirement Benefit Obligation		Impact on 2014 Service and Interest Cost	
Increase 1%	$2,635		$168	
Decrease 1%	$(2,166	)	$(136	)

Contingencies

When it is probable that an environmental or other legal liability has been incurred, a loss is recognized when the amount of the loss can be reasonably estimated. Estimates of the probability and the amount of loss are made based on currently available facts. Accounting for contingencies requires significant judgment regarding the estimated probabilities and ranges of exposure to potential liability. Our assessment of our exposure to contingencies could change to the extent there are additional future developments, or as more information becomes available. If actual obligations incurred are different from our estimates, the recognition of the actual amounts could have a material impact on our financial position, results of operations and cash flows.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each tax paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the nature of the related assets and liabilities.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements. With respect to changes in tax law, the TIPA, which was enacted December 19, 2014, did not have a material impact on the amounts provided for income taxes including our ability to realize deferred tax assets. Certain provisions of the TIPA involving primarily the extension of 50% bonus depreciation resulted in the generation of a NOL for federal and state income tax purposes in 2014. In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations had the effect of a change in law and as a result the impact was taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after January 1, 2014, with early adoption permitted. We implemented all of the provisions of the final regulations with the filing of the 2013 federal income tax return in September 2014. The adoption of the final regulations did not have a material impact on our consolidated financial statements.

See Note 14 in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K/A for additional information.

Liquidity and Capital Resources

OVERVIEW

BHC and its subsidiaries require significant cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate borrowings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate.

The most significant uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends and anticipated capital expenditures discussed in this section.

The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

Financial Position Summary	2014		2013	
Cash and cash equivalents	$21,218		$7,841	
Restricted cash and equivalents	$2,056		$2	
Short-term debt, including current maturities of long-term debt	$350,000		$82,500	
Long-term debt	$1,267,589		$1,396,948	
Stockholders’ equity	$1,353,884		$1,283,500	
Ratios				
Long-term debt ratio	48	%	53	%
Total debt ratio	54	%	54	%

As described below in the Debt and Liquidity section, in 2014, we amended and extended our corporate Revolving Credit Facility through May 29, 2019 and completed the sale of $160 million of first mortgage bonds in a private placement providing permanent financing for Cheyenne Prairie. Additionally, during 2013, we issued $800 million in long-term debt and repaid approximately $640 million in short-term and long-term borrowings.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow; however, the potential for unforeseen events affecting cash needs will continue to exist.

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

We manage liquidity needs through hedging activities, primarily in connection with seasonal needs of our utility operations (including seasonal peaks in fuel requirements), interest rate movements and commodity price movements.

Utility Factors

Our cash flows, and in turn liquidity needs in many of our regulated jurisdictions, can be subject to fluctuations in weather and commodity prices. Since weather conditions are uncontrollable, we have implemented commission-approved natural gas hedging programs in many of our regulated jurisdictions to mitigate significant changes in natural gas commodity pricing. We target hedging approximately 50% to 70% of our forecasted natural gas supply using options, futures and basis swaps.

Oil and Gas Factors

Our cash flows in our Oil and Gas segment can be subject to fluctuations in commodity prices. Significant changes in crude oil or natural gas commodity prices can have a significant impact on liquidity needs. Since commodity prices are uncontrollable, we have implemented a hedging program to mitigate the effects of significant changes in crude oil and natural gas commodity pricing on existing production. New production is subject to market prices until the production can be quantified and hedged. We use a price-based approach where, based on market pricing, our existing natural gas and crude oil production can be hedged using options, futures and basis swaps for a maximum term of three years forward. See "Market Risk Disclosures" for hedge details.

Interest Rates

Several of our debt instruments have a variable interest rate component which can change significantly depending on the economic climate. We deploy hedging strategies that include floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. At December 31, 2014, 82% of our interest rate exposure has been mitigated through either fixed or hedged interest rates.

We have $75 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 2 years. These swaps have been designated as cash flow hedges and accordingly their mark-to-market adjustments are recorded in accumulated other comprehensive income (loss) on the accompanying Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $6.0 million at December 31, 2014.

Until November 2013, we had $250 million notional amount de-designated interest rate swaps. We paid approximately $64 million to settle these swaps in November 2013. We recognized a $30 million non-cash pre-tax unrealized mark-to-market gain on these de-designated interest rate swaps for the year ended December 31, 2013.

Until November 2013, we also had interest rates swaps with a notional amount of $75 million designated as cash flow hedges to our Black Hills Wyoming project financing debt. We paid $8.5 million to settle these swaps upon repayment of the debt.

Federal and State Regulations

Federal

We are structured as a utility holding company which owns several regulated utilities. Within this structure, we are subject to various regulations by our commissions that can influence our liquidity. As an example, the issuance of debt by our regulated subsidiaries and the use of our utility assets as collateral generally require the prior approval of the state regulators in the state in which the utility assets are located. Furthermore, as a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is subordinate to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Income Tax

Acceleration of depreciation for tax purposes including 50% bonus depreciation was previously available for certain property placed in service during 2013. TIPA, enacted into law on December 19, 2014, extended 50% bonus depreciation generally to qualifying property placed in service during 2014. These provisions resulted in approximately $122 million of tax benefits for BHC as indicated in the table below:

(in millions)	2014	2013	2012
Tax benefit	$67	$24	$31

In addition, bonus depreciation applies to qualifying property whose construction began before 2015, but will be placed in service on or before December 31, 2016. No projects will qualify under this provision. The additional depreciation deductions will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2020 based on current projections.

The cash generated by bonus depreciation is an acceleration of tax benefits that we would have otherwise received over 15 to 20 years. Additionally, from a regulatory perspective, while the capital additions at the Company's regulated businesses generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate future rate increases related to capital additions.

See Note 14 in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K/A for additional information.

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring May 29, 2019 and our ability to access the public and private capital markets through debt and securities offerings when necessary.

Cash Collateral

Under contractual agreements and exchange requirements, BHC or its subsidiaries have collateral requirements, which if triggered, require us to post cash collateral positions with the counterparty to meet these obligations.

We have posted the following amounts of cash collateral with counterparties at December 31 (in thousands):

Purpose of Cash Collateral	2014	2013
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$20,007	$10,123
Oil and Gas Derivatives	4,392	2,501
Total Cash Collateral Positions	$24,399	$12,624

DEBT

Operating Activities

Our principal sources to meet day-to-day operating cash requirements are cash from operations and our corporate Revolving Credit Facility.

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, from May 29, 2014 through December 31, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. A commitment fee was charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

Our Revolving Credit Facility at December 31, 2014, had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at December 31, 2014	Letters of Credit at December 31, 2014	Available Capacity at December 31, 2014
Revolving Credit Facility	May 29, 2019	$500	$75	$35	$390

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and maintaining a certain recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of December 31, 2014.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Capital Resources

Our principal sources for our long-term capital needs have been issuances of long-term debt securities by the Company and its subsidiaries along with proceeds obtained from public and private offerings of equity.

Recent Financing Transactions

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43%

coupon first mortgage bonds due October 20, 2044 and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35% coupon $12 million pollution control revenue bonds, originally due October 1, 2024.

On November 19, 2013, we entered into a new $525 million, 4.25% unsecured note expiring on November 30, 2023. The proceeds from this new debt were used to:

- Redeem our $250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest.

- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of $87 million originally due on December 9, 2016 and settle the interest rate swaps designated to this project financing of $8.5 million.

- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million.

- Pay down $55 million of the Revolving Credit Facility.

- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new two-year $275 million term loan expiring on June 19, 2015. The proceeds from this new term loan repaid the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on September 30, 2013 and $25 million in short-term borrowing under our Revolving Credit Facility. At December 31, 2014, the cost of borrowing under this new term loan was 1.313% (LIBOR plus a margin of 1.125%).

Future Financing Plans

During the next three years, BHC plans to consider completing the following financing activities to take advantage of the current, relatively-low interest rate environment:

- Evaluate alternatives for the $275 million term loan due June 19, 2015.

Cross-Default Provisions

Our $275 million corporate term loan contains cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to make timely payments of debt obligations or triggered other default provisions under any debt agreement totaling in the aggregate principal amount of $35 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions; however the threshold principal amount is $50 million.

The Revolving Credit Facility prohibits us from paying cash dividends if we are in default or if paying dividends would cause us to be in default.

Equity

Based on our current capital spending forecast, we do not anticipate the need to access the equity capital markets in the next three years.

Shelf Registration

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. This shelf registration expires in August 2017. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2014, we had approximately 45 million shares of common stock outstanding and no shares of preferred stock outstanding.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors which will be evaluated and approved by our Board of Directors.

In January 2015, our Board of Directors declared a quarterly dividend of $0.405 per share or an annualized equivalent dividend rate of $1.62 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2014	2013	2012
Dividend Payout Ratio	53%	58%	64%
Dividends Per Share	$1.56	$1.52	$1.48

Our three-year compound annualized dividend growth rate was 2.2% and all dividends were paid out of available operating cash flows.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and the use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. As a result of our holding company structure, our right as a common shareholder, to receive assets from any of our direct or indirect subsidiaries upon a subsidiary’s liquidation or reorganization, is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.
Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed .65 to 1.00. As of December 31, 2014, we were in compliance with these covenants.

Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than .60 to 1.00. Our utilities in Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2014, the restricted net assets at our Electric and Gas Utilities were approximately $315 million.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (1.3550% at December 31, 2014). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, money pool balances included (in thousands):

	Borrowings From (Loans To) Money Pool Outstanding	
Subsidiary	2014	2013
Black Hills Utility Holdings	$88,551	$128,587
Black Hills Power	(68,626)	(17,293)
Cheyenne Light	28,663	65,772
Total Money Pool borrowings from Parent	$48,588	$177,066

CASH FLOW ACTIVITIES

The following table summarizes our cash flows (in thousands):

	2014	2013	2012
Cash provided by (used in)			
Operating activities	$323,457	$324,629	$316,971
Investing activities	$(401,147)	$(349,278)	$11,169
Financing activities	$91,067	$17,028	$(371,446)

2014 Compared to 2013

Operating Activities:

Net cash provided by operating activities was $1.2 million lower than in 2013 primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $44 million higher than prior year;

- Net outflow from operating assets and liabilities of continuing operations were $49 million higher than prior year, primarily attributable to:

  * Increased working capital requirements of approximately $39 million resulting from higher commodity prices experienced in 2014 which created an increase in fuel cost adjustments recorded in regulatory assets at our Electric and Gas Utilities;

  * Increase in accounts receivable of approximately $17 million as a result of increased revenue and increased commodity costs in 2014;

  * Receipt in 2013 of approximately $8.4 million from a government grant relating to the Busch Ranch Wind Project.

- A $10 million contribution in 2014 to our defined benefit plans compared to $13 million in 2013; and

- 2013 included cash outflows from operating activities of $1.0 million for post-closing adjustments resulting from the sale of our Energy Marketing segment in 2012.

Investing Activities:

Net cash used in investing activities was $401 million in 2014, which was an increase in outflows of $52 million from 2013 primarily due to the following:

- In 2014, we had higher capital expenditures with an increase of $44 million primarily due the increase at our Oil and Gas segment.

Financing Activities:

Net cash provided by financing activities was $91 million in 2014, which was an increase in inflow of $74 million from 2013 primarily due to the following:

- In 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie;

- In 2014, we repaid $12 million of Black Hills Power's pollution control bonds;

- In 2014, we received $22 million from the sale of an asset at our Power Generation segment. Under GAAP, this transaction did not qualify as the sale of an asset and the proceeds are presented as a financing activity;

- In 2014, net cash payments on our revolving credit facility increased $44 million over 2013, in addition to the 2013 revolving credit facility payments described below;

- In 2013, we re-paid $250 million senior unsecured notes plus a make-whole premium of approximately $8.5 million, paid off the Black Hills Wyoming project debt for approximately $96 million with settlement of the associated interest rate swaps for approximately $8.5 million, repaid $55 million on Revolving Credit Facility and settled the de-designated interest rate swaps for approximately $64 million with proceeds from issuance of a senior unsecured notes for $525 million;

- In 2013, we entered into a long-term Corporate term loan for $275 million which was primarily used to repay the $100 million long-term term loan, the $150 million short-term term loan and a portion of the Revolving Credit Facility; and

- Cash dividends on common stock of $70 million were paid in 2014 compared to $68 million paid in 2013.

2013 Compared to 2012

Operating Activities:

Net cash provided by operating activities was $7.7 million higher than in 2012 primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $24 million higher than prior year;

- Net outflow from operating assets and liabilities of continuing operations were $14 million higher than prior year. The variance primarily related to increased natural gas inventory, a decrease in accounts payable of approximately $9.0 million due to the expiration of Colorado Electric's contract with PSCo at December 31, 2011, the return of cash collateral from our de-designated interest rate swaps of $6.0 million and other normal working capital changes;

- A $13 million contribution in 2013 to our defined benefit plans compared to $25 million in 2012; and
- 2013 included cash outflows from operating activities of $0.9 million for post-closing adjustments resulting from the sale of our Energy Marketing segment in 2012 compared to 2012, which included a $21 million cash inflow from operating activities in our Energy Marketing segment.

Investing Activities:

Net cash used in investing activities was $349 million in 2013, which was an increase in outflows of $360 million from 2012 primarily due to the following:

- In 2012, proceeds from sale of assets was $254 million which included $228 million from the sale of a majority of our Williston Basin assets by our Oil and Gas segment and $25 million from the partial sale of the Busch Ranch Wind project;

- In 2012, we received proceeds of $108 million from the sale of Enserco; and

- In 2013, we had comparable capital expenditures to 2012, with an increase of $5.6 million primarily due to the construction of Cheyenne Prairie.

Financing Activities:

Cash provided by financing activities was $17 million in 2013, which was an increase in inflow of $388 million from 2012 primarily due to the following:

- In 2013, we re-paid $250 million senior unsecured notes plus a make-whole premium of approximately $8.5 million, paid off the Black Hills Wyoming project debt for approximately $96 million with settlement of the associated interest rate swaps for approximately $8.5 million, repaid $55 million on Revolving Credit Facility and settled the de-designated interest rate swaps for approximately $64 million with proceeds from issuance of a senior unsecured notes for $525 million;

- In 2013, we entered into a long-term Corporate term loan for $275 million which was primarily used to repay the $100 million long-term term loan, the $150 million short-term term loan and a portion of the Revolving Credit Facility;

- In 2012, we repaid our $225 million senior unsecured 6.5% notes with proceeds from the sale of Williston Basin assets and Black Hills Power repaid its $6.5 million Pollution Control Revenue Bonds. The redemption of the notes required a make-whole provision payment of $7.1 million;

- In 2012, we repaid short-term borrowings from proceeds from the sale of Enserco partially offset by the use of short-term borrowings to fund the construction of Cheyenne Prairie; and

- Cash dividends on common stock of $68 million were paid in 2013 compared to $65 million paid in 2012.

CAPITAL EXPENDITURES

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next three years.

Historically, a significant portion of our capital expenditures relate primarily to assets that may be included in utility rate base, and if considered prudent by regulators, can be recovered from our utility customers. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate and are subject to rate agreements. During 2014, our Electric Utilities' capital expenditures included the completion of Cheyenne Prairie and improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve or expand the existing gas distribution network. In addition to our utility capital expenditures, we allocate a portion of our capital budget to Non-regulated operations with specific focus on our oil and gas drilling program. We believe that cash generated from operations and borrowing on our existing Revolving Credit Facility will be adequate to fund ongoing capital expenditures.

Historical Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows (in thousands):

	2014	2013	2012
Property additions: [a]			
Utilities -			
Electric Utilities [b]	$193,199	$222,262	$167,263
Gas Utilities	70,528	63,205	45,711
Non-regulated Energy -			
Power Generation	2,379	13,533	5,547
Coal Mining	6,676	5,528	13,420
Oil and Gas [c]	109,439	64,687	107,839
Corporate	9,046	10,319	7,376
Capital expenditures for continuing operations	391,267	379,534	347,156
Discontinued operations investing activities	—	—	824
Total expenditures for property, plant and equipment	391,267	379,534	347,980
Common stock dividends	69,636	67,587	65,262
Maturities/redemptions of long-term debt	12,200	445,906	240,077
	$473,103	$893,027	$653,319

(a) Includes accruals for property, plant and equipment.

(b) 2014 and 2013 include costs relating to Cheyenne Prairie which began construction in the spring of 2013; and 2012 included construction of our 50% ownership in the Busch Ranch Wind Project.

(c) Increase in 2014 expenditures was due to drilling and completion delays experienced in 2013.

Forecasted Capital Expenditure Requirements

Our primary capital expenditure requirements for the three years ended December 31 are expected to be as follows (in thousands):

	2015	2016	2017
Utilities:			
Electric Utilities	$229,300	$225,400	$135,600
Gas Utilities	83,600	60,100	71,800
Cost of Service Gas	—	40,000	50,000
Non-regulated Energy:			
Power Generation	8,000	2,000	2,600
Coal Mining	7,000	6,000	6,600
Oil and Gas	123,000	122,000	120,000
Corporate	6,100	1,500	3,600
	$457,000	$457,000	$390,200

We continue to evaluate potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates identified above.

CREDIT RATINGS AND COUNTERPARTIES

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect the Company's ability to maintain or expand its businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2014:

Rating Agency	Senior Unsecured Rating	Outlook
S&P	BBB	Stable
Moody's (a)	Baa1	Stable
Fitch (b)	BBB+	Stable

(a) On January 30, 2014, Moody’s upgraded the BHC credit rating to Baa1 with a Stable outlook.
(b) On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a Stable outlook.

Our fees and interest payments under various corporate debt agreements are based on the higher credit rating of S&P or Moody’s. If either S&P or Moody’s downgraded our senior unsecured debt, we may be required to pay additional fees and incur higher interest rates under current bank credit agreements.

The following table represents the credit ratings of Black Hills Power at December 31, 2014:

Rating Agency	Senior Secured Rating
S&P	A-
Moody's *	A1
Fitch **	A

* On January 30, 2014, Moody’s upgraded the BHP credit rating to A1 with a Stable outlook.
** On June 13, 2014, Fitch upgraded the BHP credit rating to A with a Stable outlook.

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2014. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[(a)(b)]	$1,544,855	$275,000	$—	$—	$1,269,855
Unconditional purchase obligations[(c)]	694,999	183,116	322,583	150,181	39,119
Operating lease obligations[(d)]	21,055	9,962	5,726	2,709	2,658
Other long-term obligations[(e)]	47,386	—	—	—	47,386
Employee benefit plans[(f)]	158,521	15,081	47,595	32,030	63,815
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	32,193	—	10,357	4,010	17,826
Notes payable	75,000	75,000	—	—	—
Total contractual cash obligations[(h)]	$2,574,009	$558,159	$386,261	$188,930	$1,440,659

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(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period and are not included within the long-term debt balances presented: $68 million in 2015, $65 million in 2016, $65 million in 2017, $65 million in 2018 and $60 million in 2019. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2014.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas purchases, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charge under the PPAs and the commodity price under the gas purchase contracts are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2014 and price assumptions using existing prices at December 31, 2014. Our transmission obligations are based on filed tariffs as of December 31, 2014. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. The gathering commitments for our Oil and Gas segment are described in Part I, Delivery Commitments, of our our Original Filing for 2014.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities, Coal Mining and Oil and Gas segments as discussed in Note 7 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K/A.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2024.

(g) Years 1-3 include an estimated reversal of approximately $6.2 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction.

(h) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2014. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2014, we had outstanding guarantees as indicated in the table below. For more information on these guarantees, see Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K/A.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2014	Year Expiring
Indemnification for subsidiary reclamation/surety bonds [(a)]	$63,900	Ongoing
	$63,900	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

During the second quarter of 2014, guarantees of Black Hills Utility Holdings’ payment obligations up to $70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $35 million in letters of credit issued under our Revolving Credit Facility at December 31, 2014.

Market Risk Disclosures

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures.

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt and our other short-term and long-term debt instruments as described in Notes 5 and 6 of our Notes to Consolidated Financial Statements.

Our exposure to these market risks is affected by a number of factors including the size, duration and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates and the liquidity of the related interest rate and commodity markets.

The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Utilities Group

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in five states. All of our utilities have GCA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to "true-up" billed amounts to match the actual natural gas cost we incurred. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our regulated electric utilities that serves a purpose similar to the GCAs for our regulated gas utilities. To the extent that our fuel and purchased power costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer. These adjustments are subject to periodic prudence reviews by the state utility commissions.

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required, by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income (Loss) or the Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

The fair value of our Utilities Group derivative contracts at December 31 is summarized below (in thousands):

	2014		2013	
Net derivative liabilities	$(16,914	)	$(6,071	)
Cash collateral	20,007		10,123	
	$3,093		$4,052	

Oil and Gas

Oil and Gas Exploration and Production

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. Our hedging policy allows our natural gas and crude oil production from proven producing reserves to be hedged for a period up to three years in the future. Some of our commodity contracts are subject to master netting agreements, where our asset and liability positions include cash collateral that allow us to settle positive and negative positions.

We have entered into agreements to hedge a portion of our estimated 2015 and 2016 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place as of December 31, 2014, are as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2015					
Swaps - MMBtu	1,215,000	1,180,000	955,000	1,000,000	4,350,000
Weighted Average Price per MMBtu	$4.24	$4.03	$4.00	$4.04	$4.08
2016					
Swaps - MMBtu	585,000	557,500	545,000	545,000	2,232,500
Weighted Average Price per MMBtu	$3.91	$3.98	$4.08	$3.90	$3.97

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2015					
Swaps - Bbls	55,500	51,000	42,000	36,000	184,500
Weighted Average Price per Bbl	$89.98	$87.84	$88.18	$87.92	$88.58
2016					
Swaps - Bbls	39,000	39,000	36,000	36,000	150,000
Weighted Average Price per Bbl	$84.55	$84.55	$84.55	$84.55	$84.55

The fair value of our Oil and Gas segment's derivative contracts at December 31 is summarized below (in thousands):

	2014	2013
Net derivative asset (liability)	$14,684	$(869)
Cash collateral (received) paid	(10,292)	2,500
	$4,392	$1,631

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At December 31, 2014, we had $75 million of notional amount floating-to-fixed interest rate swaps, with a maximum term of 2 years. These swaps have been designated as cash flow hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets.

Further details of the swap agreements are set forth in Note 8 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K/A.

On December 31, 2014 and December 31, 2013, our interest rate swaps and related balances were as follows (dollars in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Liabilities, net of Cash Collateral	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Unrealized Gain (Loss)
December 31, 2014							
Interest rate swaps	$75,000	4.97 %	2	$3,340	$2,680	$ (6,020)	$—
December 31, 2013							
Interest rate swaps	$75,000	4.97 %	3	$3,474	$5,614	$ (9,088)	$—

Based on December 31, 2014 market interest rates and balances, a loss of approximately $3.3 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (dollars in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt							
Fixed rate[(a)]	$—	$—	$—	$—	$—	$1,250,000	$1,250,000
Average interest rate [(b)]	— %	— %	— %	— %	— %	5.2 %	5.2 %
Variable rate	$275,000	$—	$—	$—	$—	$19,855	$294,855
Average interest rate [(b)]	1.31 %	— %	— %	— %	— %	0.18 %	1.24 %
Total long-term debt	$275,000	$—	$—	$—	$—	$1,269,855	$1,544,855
Average interest rate [(b)]	1.31 %	— %	— %	— %	— %	5.12 %	4.44 %

(a) Excludes unamortized premium or discount.
(b) The average interest rates do not include the effect of interest rate swaps.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

We seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

At December 31, 2014, our credit exposure included a $0.6 million exposure to a non-investment grade rural electric utility cooperative. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade companies, municipal cooperatives and federal agencies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K/A for information on new accounting standards adopted in 2014 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management’s Report on Internal Control over Financial Reporting (Revised)

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014, based on the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission “COSO”. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, at the time that the Original Filing was filed on February 25, 2015, we concluded that our internal control over financial reporting was effective as of December 31, 2014.

In connection with the immaterial corrections discussed in the Explanatory Note to this Annual Report on Form 10-K/A and Note 1 of the Notes to the Consolidated Financial Statements included herein, management, including our Chief Executive Officer and Chief Financial Officer, reassessed the effectiveness of our internal controls over financial reporting as of December 31, 2014. Based on this reassessment using the COSO criteria, management has concluded that we did not maintain effective internal control over financial reporting as of December 31, 2014 because of a deficiency in the level of training in performing the control over the full cost ceiling test write-down impairment calculation, specifically related to evaluating and correctly accounting for the treatment of tax amounts associated with the calculation. Management concluded that this deficiency was a material weakness as defined in the Securities and Exchange Commission regulations.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation’s financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2014. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income (loss), common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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, such consolidated financial statements present fairly, in all material respects, the financial position of Black Hills Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2015, August 6, 2015, as to the effects of the material weakness described in Management's Report on Internal Control Over Financial Reporting (revised), which report expressed an adverse opinion on the effectiveness of Company's internal control over financial reporting because of a material weakness.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2015 (August 6, 2015 as to the effects of the restatement discussed in Note 1)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting (revised). Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment: a deficiency in the level of training in performing the control over the full cost ceiling test write-down impairment calculation, specifically related to evaluating and correctly accounting for the treatment of tax amounts associated with the calculation. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014 of the Company and this report does not affect our report on such financial statements and financial statement schedule.

In our opinion, because of the effect of the material weakness identified above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014 of the Company and our report dated February 24, 2015 (August 6, 2015 as to the effects of the restatement revisions discussed in Note 1) expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2015 (August 6, 2015 as to the effects of the material weakness described in Management's Report on Internal Control Over Financial Reporting (revised))

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	December 31, 2014	December 31, 2013	December 31, 2012
	(in thousands, except per share amounts)		
Revenue:			
Utilities	$1,300,969	$1,191,133	$1,064,813
Non-regulated energy	92,601	84,719	109,071
Total revenue	1,393,570	1,275,852	1,173,884
Operating expenses:			
Utilities -			
Fuel, purchased power and cost of natural gas sold	581,782	492,147	407,066
Operations and maintenance	270,954	261,919	242,367
Non-regulated energy operations and maintenance	88,141	83,762	85,830
Gain on sale of operating assets	—	—	(75,854)
Depreciation, depletion and amortization	144,745	137,324	145,923
Impairment of long-lived assets	—	—	49,571
Taxes - property, production and severance	43,580	40,012	40,487
Other operating expenses	500	1,243	2,052
Total operating expenses	1,129,702	1,016,407	897,442
Operating income	263,868	259,445	276,442
Other income (expense):			
Interest charges -			
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(73,017)	(113,979)	(117,754)
Allowance for funds used during construction - borrowed	1,075	1,130	3,462
Capitalized interest	982	1,061	682
Unrealized gain (loss) on interest rate swaps, net	—	30,169	1,882
Interest income	1,925	1,723	1,957
Allowance for funds used during construction - equity	994	607	540
Other expense	(377)	(694)	(71)
Other income	2,065	1,971	2,486
Total other income (expense)	(66,353)	(78,012)	(106,816)
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	197,515	181,433	169,626
Equity in earnings (loss) of unconsolidated subsidiaries	(1)	(86)	10
Income tax benefit (expense)	(66,625)	(63,040)	(60,219)
Income (loss) from continuing operations	130,889	118,307	109,417
Income (loss) from discontinued operations, net of tax	—	(884)	(6,977)
Net income (loss) available for common stock	$130,889	$117,423	$102,440
Earnings (loss) per share of common stock:			
Earnings (loss) per share, Basic -			
Income (loss) from continuing operations, per share	$2.95	$2.68	$2.50
Income (loss) from discontinued operations, per share	—	(0.02)	(0.16)

Total income (loss) per share, Basic	$2.95	$2.66	$2.34
Earnings (loss) per share, Diluted -			
Income (loss) from continuing operations, per share	$2.93	$2.66	$2.48
Income (loss) from discontinued operations, per share	—	(0.02)	(0.16)
Total income (loss) per share, Diluted	$2.93	$2.64	$2.32
Weighted average common shares outstanding:			
Basic	44,394	44,163	43,820
Diluted	44,598	44,419	44,073

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years ended (in thousands)	December 31, 2014	December 31, 2013	December 31, 2012
Net income (loss) available for common stock	$130,889	$117,423	$102,440
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $5,004, $(3,813) and $296, respectively)	(10,590)	8,237	(542)
Benefit plan liability adjustments - prior service (costs) (net of tax of $(17), $185 and $86, respectively)	237	(406)	(157)
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(348), $(971) and $0, respectively)	646	1,820	—
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $76, $88 and $0, respectively)	(141)	(165)	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(5,239), $(2,445) and $887, respectively)	8,906	4,534	(1,268)
Reclassification adjustment of cash flow hedges settled and included in net income (loss) (net of tax of $(2,344), $(2,016) and $534, respectively)	3,320	4,046	(643)
Other comprehensive income (loss), net of tax	2,378	18,066	(2,610)
Comprehensive income (loss)	$133,267	$135,489	$99,830

See Note 15 for additional disclosures related to Comprehensive Income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2014 (in thousands)	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$21,218	$7,841
Restricted cash and equivalents	2,056	2
Accounts receivable, net	189,992	177,573
Materials, supplies and fuel	91,191	88,478
Derivative assets, current	—	717
Income tax receivable, net	2,053	1,460
Deferred income tax assets, net, current	48,288	18,889

Regulatory assets, current	74,396	24,451
Other current assets	24,842	25,877
Total current assets	454,036	345,288
Investments	17,294	16,697
Property, plant and equipment	4,563,400	4,259,445
Less accumulated depreciation and depletion	(1,357,929)	(1,306,390)
Total property, plant and equipment, net	3,205,471	2,953,055
Other assets:		
Goodwill	353,396	353,396
Intangible assets, net	3,176	3,397
Derivative assets, non-current	—	—
Regulatory assets, non-current	183,443	138,197
Other assets, non-current	29,086	27,906
Total other assets, non-current	569,101	522,896
TOTAL ASSETS	$4,245,902	$3,837,936

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of December 31, 2014	December 31, 2013
	(in thousands, except share amounts)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$124,139	$130,416
Accrued liabilities	170,115	151,277
Derivative liabilities, current	3,340	3,474
Regulatory liabilities, current	3,687	10,727
Notes payable	75,000	82,500
Current maturities of long-term debt	275,000	—
Total current liabilities	651,281	378,394
Long-term debt, net of current maturities	1,267,589	1,396,948
Deferred credits and other liabilities:		
Deferred income tax liabilities, net, non-current	511,952	419,293
Derivative liabilities, non-current	2,680	5,614
Regulatory liabilities, non-current	145,144	109,429
Benefit plan liabilities	158,966	111,479
Other deferred credits and other liabilities	154,406	133,279
Total deferred credits and other liabilities	973,148	779,094
Commitments and contingencies (See Notes 5, 6, 7, 8, 13, 17, 18 and 19)		
Stockholders' equity:		
Common stock $1 par value; 100,000,000 shares authorized; issued: 44,714,072 and 44,550,239 shares, respectively	44,714	44,550
Additional paid-in capital	748,840	742,344
Retained earnings	577,249	515,996
Treasury stock at cost - 42,226 and 50,877 shares, respectively	(1,875)	(1,968)
Accumulated other comprehensive income (loss)	(15,044)	(17,422)
Total stockholders' equity	1,353,884	1,283,500
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,245,902	$3,837,936

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2014	December 31, 2013	December 31, 2012
	(in thousands)		
Operating activities:			
Net income available for common stock	$130,889	$117,423	$102,440
(Income) loss from discontinued operations, net of tax	—	884	6,977
Income (loss) from continuing operations	130,889	118,307	109,417
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	144,745	137,324	145,923
Deferred financing cost amortization	2,127	6,763	5,555
Impairment of long-lived assets	—	—	49,571
Gain on sale of operating assets	—	—	(75,854)
Stock compensation	9,329	12,595	8,271
Unrealized (gain) loss on interest rate swaps, net	—	(30,169)	(1,882)
Deferred income taxes	70,232	65,216	51,535
Employee benefit plans	14,814	22,194	20,973
Other adjustments, net	14,415	9,826	4,929
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(4,563)	(5,770)	6,343
Accounts receivable, unbilled revenues and other current assets	(65,091)	(13,921)	13,739
Accounts payable and other current liabilities	16,027	15,336	(10,713)
Contributions to defined benefit pension plans	(10,200)	(12,500)	(25,350)
Other operating activities, net	733	312	(6,670)
Net cash provided by operating activities of continuing operations	323,457	325,513	295,787
Net cash provided by (used in) operating activities of discontinued operations	—	(884)	21,184
Net cash provided by operating activities	323,457	324,629	316,971
Investing activities:			
Property, plant and equipment additions	(398,494)	(354,749)	(349,129)
Proceeds from sale of assets	—	—	253,791
Other investing activities	(2,653)	5,471	(180)
Net cash provided by (used in) investing activities of continuing operations	(401,147)	(349,278)	(95,518)
Proceeds from sale of business operations	—	—	107,511
Net cash provided by (used in) investing activities of discontinued operations	—	—	(824)
Net cash provided by (used in) investing activities	(401,147)	(349,278)	11,169
Financing activities:			
Dividends paid on common stock	(69,636)	(67,587)	(65,262)
Common stock issued	3,251	4,354	4,726
Short-term borrowings - issuances	396,250	337,650	203,753
Short-term borrowings - repayments	(403,750)	(532,150)	(271,753)
Long-term debt - issuance	160,000	800,000	—
Long-term debt - repayments	(12,200)	(445,906)	(240,077)

De-designated interest rate swap settlement	—	(63,939)	—
Other financing activities	17,152	(15,394)	(2,833)
Net cash provided by (used in) financing activities of continuing operations	91,067	17,028	(371,446)
Net cash provided by (used in) financing activities of discontinued operations	—	—	—
Net cash provided by (used in) financing activities	91,067	17,028	(371,446)
Net change in cash and cash equivalents	13,377	(7,621)	(43,306)
Cash and cash equivalents beginning of year *	7,841	15,462	58,768
Cash and cash equivalents end of year	$21,218	$7,841	$15,462

* Cash and cash equivalents include cash of discontinued operations of $37 million at December 31, 2011.

See Note 16 for supplemental disclosure of cash flow information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Common Stock		Treasury Stock					
(in thousands except share)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Total
Balance at December 31, 2011	43,957,502	$43,958	32,766	$(970)	$722,623	$428,982	$(32,878)	$1,161,715
Net income (loss) available for common stock	—	—	—	—	—	102,440	—	102,440
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(2,610)	(2,610)
Dividends on common stock	—	—	—	—	—	(65,262)	—	(65,262)
Share-based compensation	219,946	220	39,016	(1,275)	7,095	—	—	6,040
Tax effect of share-based compensation	—	—	—	—	117	—	—	117
Dividend reinvestment and stock purchase plan	100,741	100	—	—	3,282	—	—	3,382
Other stock transactions	—	—	—	—	(22)	—	—	(22)
Balance at December 31, 2012	44,278,189	$44,278	71,782	$(2,245)	$733,095	$466,160	$(35,488)	$1,205,800
Net income (loss) available for common stock	—	—	—	—	—	117,423	—	117,423
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	18,066	18,066
Dividends on common stock	—	—	—	—	—	(67,587)	—	(67,587)
Share-based compensation	190,172	190	(20,905)	277	5,400	—	—	5,867
Tax effect of share-based compensation	—	—	—	—	410	—	—	410
Dividend reinvestment and stock purchase plan	66,878	67	—	—	3,062	—	—	3,129
Other stock transactions	15,000	15	—	—	377	—	—	392
Balance at December 31, 2013	44,550,239	$44,550	50,877	$(1,968)	$742,344	$515,996	$(17,422)	$1,283,500
Net income (loss) available for common stock	—	—	—	—	—	130,889	—	130,889
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	2,378	2,378
Dividends on common stock	—	—	—	—	—	(69,636)	—	(69,636)
Share-based compensation	111,507	112	(8,651)	93	4,210	—	—	4,415
Tax effect of share-based compensation	—	—	—	—	(499)	—	—	(499)
Dividend reinvestment and stock purchase plan	52,326	52	—	—	2,826	—	—	2,878
Other stock transactions	—	—	—	—	(41)	—	—	(41)
Balance at December 31, 2014	44,714,072	$44,714	42,226	$(1,875)	$748,840	$577,249	$(15,044)	$1,353,884

Dividends per share paid were $1.56, $1.52 and $1.48 for the years ended December 31, 2014, 2013 and 2012, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2014, 2013 and 2012

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a diversified energy company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, operates in two primary business groups: Utilities and Non-regulated Energy.

The Utilities Group includes our Electric Utilities and Gas Utilities segments. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric and the electric and natural gas utility operations of Cheyenne Light, which supply regulated electric utility services to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility services to Cheyenne, Wyoming and vicinity. Gas Utilities consist of the operating results of the regulated natural gas utility operations of Colorado Gas, Nebraska Gas, Iowa Gas and Kansas Gas.

The Non-regulated Energy Group includes our Power Generation, Coal Mining and Oil and Gas segments. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Coal Mining, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. Oil and Gas, which is conducted through BHEP and its subsidiaries, engages in crude oil and natural gas exploration and production activities in Colorado, Louisiana, Montana, Oklahoma, New Mexico, North Dakota, Wyoming, Texas and California. These businesses are aggregated for reporting purposes as Non-regulated Energy.

On February 29, 2012, we sold Enserco, our Energy Marketing segment, which resulted in this segment being reclassified as discontinued operations. See Note 21 for additional information.

For further descriptions of our reportable business segments, see Note 4.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain 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. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. Investment in non-controlled entities over which we have the ability to exercise significant influence over operating and financial policies are accounted for using the equity method of accounting. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for our proportionate share of earnings and losses and distributions. Under this method, a proportionate share of pretax income is recorded as Equity earnings (loss) of unconsolidated subsidiaries. All inter-company balances and transactions have been eliminated in consolidation. For additional information on inter-company revenues, see Note 4.

Our Consolidated Statements of Income include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie and the BHEP gas processing plant. See Note 3 for additional information.

As a result of the sale of our Energy Marketing segment, amounts associated with this segment have been reclassified as discontinued operations on the accompanying Consolidated Financial Statements. See Note 21 for additional information.

Correction of Immaterial Errors

In preparing our condensed consolidated financial statements for the quarter ended June 30, 2015, we identified immaterial errors that impacted our previously issued consolidated financial statements. The prior period errors originated in the year ended December 31, 2008 and related to our oil and gas full cost ceiling impairment calculation to determine whether the net book value of the our oil and gas properties exceeded the ceiling. Specifically, the errors related to evaluating and correctly accounting for the treatment of tax related amounts associated with the calculation. The original errors identified caused an understatement of 2008, 2009, 2012 and Q1 2015 noncash ceiling test impairment calculations, which resulted in an overstatement of depletion expense from 2009 through March 31, 2015, and an understatement of the 2012 gain on sale of oil and gas properties.
In accordance with Staff Accounting Bulletin (SAB) No. 99, Materiality, and SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, we evaluated these errors, including both qualitative and quantitative considerations, and concluded that the errors did not, individually or in the aggregate, result in a material misstatement of our previously issued consolidated financial statements.

The following tables present the revisions to particular line items resulting from the corrections of these errors in this Annual Report on Form 10-K/A. The errors relate entirely to our Oil and Gas segment.

CONSOLIDATED STATEMENTS OF INCOME

	As of December 31, 2014			As of December 31, 2013		
	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
	(in thousands expect per share amounts)					
Depreciation, depletion and amortization	$148,083	$(3,338)	$144,745	$141,217	$(3,893)	$137,324
Total operating expenses	$1,133,040	$(3,338)	$1,129,702	$1,020,300	$(3,893)	$1,016,407
Operating income	$260,530	$3,338	$263,868	$255,552	$3,893	$259,445
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	$194,177	$3,338	$197,515	$177,540	$3,893	$181,433
Income tax benefit (expense)	$(65,395)	$(1,230)	$(66,625)	$(61,608)	$(1,432)	$(63,040)
Income (loss) from continuing operations	$128,781	$2,108	$130,889	$115,846	$2,461	$118,307
Net income (loss) available for common stock	$128,781	$2,108	$130,889	$114,962	$2,461	$117,423
Earnings (loss) per share of common stock:						
Earnings (loss) per share, Basic - Income (loss) from continuing operations, per share	$2.90	$0.05	$2.95	$2.62	$0.06	$2.68
Income (loss) from discontinued operations, per share	—	—	—	(0.02)	—	(0.02)
Total income (loss) per share, Basic	$2.90	$0.05	$2.95	$2.60	$0.06	$2.66

Earnings (loss) per share, Diluted -						
Income (loss) from continuing operations, per share	$2.89	$0.04	$2.93	$2.61	$0.05	$2.66
Income (loss) from discontinued operations, per share	—	—	—	(0.02)	—	(0.02)
Total income (loss) per share, Diluted	$2.89	$0.04	$2.93	$2.59	$0.05	$2.64

65

As of December 31, 2012	As Reported	Adjustment	As Revised
	(in thousands expect per share amounts)		
Gain on sale of operating assets	$(29,129)	$(46,725)	$(75,854)
Depreciation, depletion and amortization	$154,632	$(8,709)	$145,923
Impairment of long-lived assets	$26,868	$22,703	$49,571
Total operating expenses	$930,173	$(32,731)	$897,442
Operating income	$243,711	$32,731	$276,442
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	$136,895	$32,731	$169,626
Income tax benefit (expense)	$(48,400)	$(11,819)	$(60,219)
Income (loss) from continuing operations	$88,505	$20,912	$109,417
Net income (loss) available for common stock	$81,528	$20,912	$102,440
Earnings (loss) per share of common stock:			
Earnings (loss) per share, Basic -			
Income (loss) from continuing operations, per share	$2.02	$0.48	$2.50
Income (loss) from discontinued operations, per share	(0.16)	—	(0.16)
Total income (loss) per share, Basic	$1.86	$0.48	$2.34
Earnings (loss) per share, Diluted -			
Income (loss) from continuing operations, per share	$2.01	$0.47	$2.48
Income (loss) from discontinued operations, per share	(0.16)	—	(0.16)
Total income (loss) per share, Diluted	$1.85	$0.47	$2.32

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Consolidated Statements of Comprehensive Income for the year ended December 31,								
	2014			2013			2012		
	As Reported	Adjustment	As Revised	As Reported	Adjustment	As Revised	As Reported	Adjustment	As Revised
	(in thousands)								
Net income (loss)	$128,781	$2,108	$130,889	$114,962	$2,461	$117,423	$81,528	$20,912	$102,440
Comprehensive Income (loss)	$131,159	$2,108	$133,267	$133,028	$2,461	$135,489	$78,918	$20,912	$99,830

CONSOLIDATED BALANCE SHEET

	As of December 31, 2014			As of December 31, 2013		
	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
	(in thousands)					
Accumulated Depreciation and Depletion	$(1,324,025)	$(33,904)	$(1,357,929)	$(1,269,148)	$(37,242)	$(1,306,390)
Total property, plant and equipment, net	$3,239,375	$(33,904)	$3,205,471	$2,990,297	$(37,242)	$2,953,055
TOTAL ASSETS	$4,279,806	$(33,904)	$4,245,902	$3,875,178	$(37,242)	$3,837,936
Deferred income tax liability, non-current	$523,716	$(11,764)	$511,952	$432,287	$(12,994)	$419,293

Total deferred credits and other liabilities	$984,912	$(11,764)	$973,148	$792,088	$(12,994)	$779,094
Retained earnings	$599,389	$(22,140)	$577,249	$540,244	$(24,248)	$515,996
Total stockholders' equity	$1,376,024	$(22,140)	$1,353,884	$1,307,748	$(24,248)	$1,283,500
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,279,806	$(33,904)	$4,245,902	$3,875,178	$(37,242)	$3,837,936

66

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2014			Year Ended December 31, 2013		
	As Reported	Adjustments	As Revised	As Reported	Adjustments	As Revised
	(in thousands)					
Net income (loss) available for common stock	$128,781	$2,108	$130,889	$114,962	$2,461	$117,423
Income (loss) from continuing operations	$128,781	$2,108	$130,889	$115,846	$2,461	$118,307
Adjustments to reconcile net income (loss) to net cash provided by operating activities:						
Depreciation, depletion and amortization	$148,083	$(3,338)	$144,745	$141,217	$(3,893)	$137,324
Deferred income taxes	$69,002	$1,230	$70,232	$63,784	$1,432	$65,216

	Year Ended December 31, 2012		
	As Reported	Adjustments	As Revised
	(in thousands)		
Net income (loss) available for common stock	$81,528	$20,912	$102,440
Income (loss) from continuing operations	$88,505	$20,912	$109,417
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	$154,632	$(8,709)	$145,923
Impairment of long-lived assets	$26,868	$22,703	$49,571
Gain on sale of operating assets	$(29,129)	$(46,725)	$(75,854)
Deferred income taxes	$39,716	$11,819	$51,535

The Notes to the Consolidated Financial Statements have been revised to reflect the correction of these errors for all periods presented.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Equivalents

We maintain cash accounts for various specified purposes. Therefore, we classify these amounts as restricted cash.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Utilities Group primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Non-regulated Energy Group consists of amounts due from sales of coal, crude oil and natural gas, electric energy and capacity.
We maintain an allowance for doubtful accounts which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness,

the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Following is a summary of accounts receivable as of December 31 (in thousands):

2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$59,714	$26,474	$(722)	$85,466
Gas Utilities	47,394	45,546	(781)	92,159
Power Generation	1,369	—	—	1,369
Coal Mining	3,151	—	—	3,151
Oil and Gas	5,305	—	(13)	5,292
Corporate	2,555	—	—	2,555
Total	$119,488	$72,020	$(1,516)	$189,992

2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$52,437	$23,823	$(666)	$75,594
Gas Utilities	49,162	41,195	(558)	89,799
Power Generation	1,722	—	—	1,722
Coal Mining	1,711	—	—	1,711
Oil and Gas	8,156	—	(13)	8,143
Corporate	604	—	—	604
Total	$113,792	$65,018	$(1,237)	$177,573

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price and delivery has occurred or services have been rendered. Sales tax collected from our customers is recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, our utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

For long-term non-regulated power sales agreements, revenue is recognized either in accordance with accounting standards for revenue recognition, or in accordance with accounting standards for leases, as appropriate. Under accounting standards for revenue recognition, revenue is generally recognized as the lesser of the amount billed or the average rate expected over the life of the agreement.

Natural gas and crude oil sales are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is reasonably assured. Our Oil and Gas segment records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, crude oil, condensate and NGLs is adjusted for transportation costs and other related deductions when applicable. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of (in thousands):

	December 31, 2014	December 31, 2013
Materials and supplies	$49,555	$50,196
Fuel - Electric Utilities	6,637	6,213
Natural gas in storage held for distribution	34,999	32,069
Total materials, supplies and fuel	$91,191	$88,478

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are valued using weighted-average cost. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus cost of removal, is charged to accumulated depreciation. Estimated removal costs associated with non-legal obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various class of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, a unit-of-production methodology based on plant hours run is used.

Oil and Gas Operations

We account for our oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are typically treated as adjustments to the cost of the properties with no gain or loss recognized. However, we recognized a gain on the sale of a majority of our Williston Basin assets in 2012. See Note 21 for further discussion.

Costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized. These costs are generally expected to be included in costs to be amortized within the term of the underlying lease agreement which varies in length.

Under the full cost method, net capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC, plus the lower of cost or market value of unevaluated properties. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent non-cash write-down would be charged to earnings in that period. As a result of lower natural gas prices, we recorded a non-cash ceiling test impairment of oil and gas long-lived assets included in the Oil and Gas segment in 2012. No ceiling test write-down was recorded in 2014 or 2013. See Note 12 for additional information.

The SEC definition of "reliable technology" permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to calculate PUDs to be booked at more than one location away from a producing well. We elected to include PUDs of only one location away from a producing well in our volume reserve estimate. See information on our oil and gas drilling activities in Note 20.

Companies are permitted but not required to disclose probable and possible reserves. We have elected not to report on these additional reserve categories.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives. We perform this annual review of goodwill and indefinite lived intangible assets as of November 30 each year (or more frequently if impairment indicators arise).

We performed our annual goodwill impairment tests as of November 30, 2014. We estimated the fair value of the goodwill using discounted cash flow methodology, EBITDA multiple method and an analysis of comparable transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital and long-term earnings and merger multiples for comparable companies.

Goodwill at our Electric and Gas Utilities primarily arose from the acquisition of one regulated electric and four regulated gas utilities in the Aquila Transaction. This goodwill from the Aquila Transaction was allocated approximately $246 million, or 72%, to Colorado Electric and $94 million, or 28%, to the Gas Utilities. We believe that the goodwill amount reflects the value of the relatively stable, long-lived cash flows of the regulated gas utility business, considering the regulatory environment and market growth potential and the long-lived cash flow and rate base growth opportunities at our electric utility in Colorado. Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2012	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at December 31, 2013	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at December 31, 2014	$250,487	$94,144	$8,765	$353,396

Our intangible assets represent easements, rights-of-way and trademarks and are amortized using a straight-line method based on estimated useful lives. The finite lived intangible assets are currently being amortized over 20 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2014	2013	2012
Intangible assets, net, beginning balance	$3,397	$3,620	$3,843

Additions (adjustments)	—	—	—
Amortization expense*	(221)	(223)	(223)
Intangible assets, net, ending balance	$3,176	$3,397	$3,620

* Amortization expense for existing intangible assets is expected to be $0.2 million for each year of the next five years.

Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations, other than Oil and Gas. For the Oil and Gas segment, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and depleted pursuant to our use of the full cost method. Additional information is included in Note 7.

Fair Value Measurements

Derivative Financial Instruments

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management’s best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity contracts for the Oil and Gas segment are valued under the market approach and include exchange-traded futures and basis swaps. Fair value was derived using exchange quoted settlement prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through third party sources and therefore support Level 2 disclosure.

Utilities Segment:

- The commodity contracts for the Utilities, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third party market participant since these instruments are not traded on an exchange.

Corporate Segment:

- The interest rate swaps are valued using the market valuation approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Additional information is included in Note 9.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and that changes in the derivative instrument’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met and designated accordingly, and if they qualify for certain exemptions, including the normal purchases and normal sales exemption. Each Consolidated Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists.

Accounting standards for derivatives and hedging require that the unrealized gains or losses on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting unrealized gain or loss on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument must be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exceptions, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the estimated useful life of the related debt.

Development Costs

According to accounting standards for business combinations, we expense, when incurred, development and acquisition costs associated with corporate development activities prior to acquiring or beginning construction of a project. Expensed development costs are included in Other operating expenses on the accompanying Consolidated Statements of Income.

Legal Costs

Litigation liabilities, including potential settlements, are recorded when it is both probable that a liability or settlement has been incurred and the amount can be reasonably estimated. Legal costs related to ongoing litigation are expensed as incurred.
When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, we record a loss contingency at the minimum amount in the range. If the loss contingency at issue is not both probable and reasonably estimable, we do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable.

Regulatory Accounting

Our Utilities Group follows accounting standards for regulated operations and reflects the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which would require these net assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities (in thousands):

	Maximum Amortization (in years)	As of December 31, 2014	As of December 31, 2013
Regulatory assets			
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$23,820	$16,775
Deferred gas cost adjustments [(a)(d)]	2	37,471	4,799
Gas price derivatives [(a)]	7	18,740	7,567
AFUDC [(b)]	45	12,358	12,315
Employee benefit plans [(c) (e)]	12	97,126	67,059
Environmental [(a)]	subject to approval	1,314	1,800
Asset retirement obligations [(a)]	44	3,287	3,266
Bond issue cost [(a)]	23	3,276	3,419
Renewable energy standard adjustment [(a)]	5	9,622	14,186
Flow through accounting [(c)]	35	25,887	20,916
Decommissioning costs	10	12,484	—
Other regulatory assets [(a)]	15	12,454	10,546
		$257,839	$162,648

Regulatory liabilities

Deferred energy and gas costs [a]	1	$6,496	$11,708
Employee benefit plans [c] [e]	12	53,139	34,431
Cost of removal [a]	44	78,249	64,970
Other regulatory liabilities [c]	25	10,947	9,047
		$148,831	$120,156

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73

(a) Recovery of costs, but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base, respectively.
(d) Our deferred energy, fuel cost and gas cost adjustments represent the cost of electricity and gas delivered to our electric and gas utility customers that is either higher or lower than current rates and will be recovered or refunded in future rates. Increases in the current year balances as of December 31, 2014 are primarily due to higher natural gas prices driven by demand and market conditions during our peak winter heating season. Our electric and gas utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.
(e) Increases are due to a decrease in the discount rate and a change in the mortality tables used in employee benefit plan estimates.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission.

Deferred Gas Cost Adjustment - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions.

Gas Price Derivatives - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. The 7-year term represents the maximum forward term hedged.

AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income, including costs being amortized from the Aquila Transaction.

Environmental - Environmental is associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 7 for additional details.

Bond Issue Costs - Bond issue costs are recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in a rate case settlement that was reached with respect to Black Hills Power in 2010.

In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered repairs for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - Black Hills Power and Colorado Electric received approval for regulatory treatment on the remaining net book values of their decommissioned coal plants in 2014. These balances were in Property, Plant and Equipment in 2013.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs - Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement aspect of a rate regulated environment.

Cost of Removal - Cost of removal represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal obligation for removal.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each tax paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carry forwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the nature of the related assets and liabilities.

It is our policy to apply the flow-through method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. Another acceptable accounting method and an exception to this general policy currently in our regulated businesses is to apply the deferral method whereby the credit is amortized as a reduction of income tax expense over the useful lives of the related property.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Consolidated Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 14 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing and discontinued operations is computed by dividing Income (loss) from continuing or discontinued operations by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings (loss) per share is as follows (in thousands):

	December 31, 2014	December 31, 2013	December 31, 2012
Income (loss) from continuing operations	$130,889	$118,307	$109,417
Weighted average shares - basic	44,394	44,163	43,820
Dilutive effect of:			
Equity compensation	204	256	250
Other	—	—	3
Weighted average shares - diluted	44,598	44,419	44,073
Income (loss) from continuing operations, per share - Diluted	$2.93	$2.66	$2.48

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	December 31, 2014	December 31, 2013	December 31, 2012
Equity compensation	81	22	163
Anti-dilutive shares excluded from computation of earnings (loss) per share	81	22	163

Discontinued Operations

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco Energy Inc. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. In accordance with GAAP, indirect corporate costs previously allocated to a disposal group cannot be reclassified to discontinued operations. See Note 21 for additional information.

Recently Issued and Adopted Accounting Standards

We have implemented all new accounting pronouncements that are in effect and may impact our financial statements and do not believe that there are any other new accounting pronouncements that have been issued that might have a material impact on our financial position, results of operations, or cash flows.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. ASU 2014-09 is effective for annual and interim reporting periods beginning after December 15, 2016 and early adoption is not permitted. We are currently assessing the impact, if any, that ASU 2014-09 will have on our financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements and Legislation

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforwards Exists, ASU 2013-11

In July 2013, the FASB issued an amendment to accounting for income taxes which provides guidance on financial statement presentation of an unrecognized tax benefit when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. The objective in issuing this amendment is to eliminate diversity in practice resulting from a lack of guidance on this topic in current GAAP. Under the amendment, an entity must present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the financial statements as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward except under certain conditions. The amendment is effective for fiscal years beginning after December 15, 2013 and interim periods within those years, and should be applied to all unrecognized tax benefits that exist as of the effective date. The adoption of this standard did not have any impact on our financial position, results of operations or cash flows.

Final Tangible Property Regulations, Treasury Decision 9636

In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations had the effect of a change in law and as a result, the impact should be taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after January 1, 2014, with early adoption permitted. We implemented all of the provisions of the final regulations with the filing of the 2013 federal income tax return in September 2014. The adoption of the final regulations did not have a material impact on our consolidated financial statements.

(2) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

Utilities Group	2014		2013		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$1,125,845	45	$951,138	45	25	65
Electric transmission	284,032	49	238,542	50	40	65
Electric distribution	718,342	44	666,589	44	15	65
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	152,982	21	138,263	22	3	60
Capital lease - plant in service [(b)]	261,441	20	261,441	20	20	20
Total electric plant in service	$2,547,512		$2,260,843			
Construction work in progress	49,700		203,760			
Total electric plant	2,597,212		2,464,603			
Less accumulated depreciation and amortization	484,406		472,970			
Electric plant net of accumulated depreciation and amortization	$2,112,806		$1,991,633			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 16 years remaining.

(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the PPA between Colorado Electric and Black Hills Colorado IPP. The capital lease ends in conjunction with the expiration of the PPA on December 31, 2031.

Gas Utilities	2014 Property, Plant and Equipment	2014 Weighted Average Useful Life (in years)	2013 Property, Plant and Equipment	2013 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Gas plant:						
Production	$13	37	$13	37	37	37
Gas transmission	24,090	54	24,984	54	53	57
Gas distribution	557,405	46	507,318	46	41	56
General	90,085	19	85,841	19	16	22
Total gas plant in service	671,593		618,156			
Construction work in progress	16,072		9,417			
Total gas plant	687,665		627,573			
Less accumulated depreciation and amortization	92,035		84,679			
Gas plant net of accumulated depreciation and amortization	$595,630		$542,894			

2014

Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Lives (in years) Weighted Average Useful Life	Minimum	Maximum
Power Generation	$153,779	$2,262	$156,041	$47,704	$108,337	33	2	40
Coal Mining	145,619	3,748	149,367	90,629	58,738	15	2	59
Oil and Gas	962,395	—	962,395	646,640	315,755	24	3	25
	$1,261,793	$6,010	$1,267,803	$784,973	$482,830			

2013

Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Lives (in years) Weighted Average Useful Life	Minimum	Maximum
Power Generation	$143,026	$10,491	$153,517	$43,069	$110,448	36	2	40
Coal Mining	149,067	1,156	150,223	86,306	63,917	14	2	59
Oil and Gas	852,384	—	852,384	622,576	229,808	24	3	25
	$1,144,477	$11,647	$1,156,124	$751,951	$404,173			

2014						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$5,524	$5,196	$10,720	$(3,485)	$14,205	11	5	30

(a) Accumulated depreciation, depletion and amortization at Corporate reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Colorado IPP.

2013						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$5,498	$5,647	$11,145	$(3,210)	$14,355	6	2	30

(a) Accumulated depreciation, depletion and amortization at Corporate reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Colorado IPP.

(3) JOINTLY OWNED FACILITIES

Utility Plant

Our consolidated financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities expenses are reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income. Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- Black Hills Power owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. Black Hills Power receives its proportionate share of the Wyodak Plant’s capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying Black Hills Power with coal for its share of the Wyodak Plant, our Coal Mining subsidiary, WRDC, supplies PacifiCorp’s share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC’s coal reserves.

- Black Hills Power also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW - 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay its proportionate share of the additions and replacements to and operating and maintenance expenses of the transmission tie.

- Black Hills Power owns 52% of the Wygen III coal-fired generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations. Our Coal Mining subsidiary supplies coal to Wygen III for the life of the plant.
- Colorado Electric owns 50% of the Busch Ranch Wind Project while AltaGas owns the remaining undivided ownership interest and is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind project for the life of the facility. We retain responsibility for operations of the wind farm.

Non-Regulated Plants

Our consolidated financial statements include our share of a jointly-owned non-regulated power generation facility as described below. Our share of direct expenses for the jointly-owned facility is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. Each of the respective owners is responsible for providing its own financing.

- Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Coal Mining subsidiary during the life of the facility. We retain responsibility for plant operations.

At December 31, 2014, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$110,123	$1,201	$53,816
Transmission Tie	$19,648	$—	$4,976
Wygen I	$109,040	$1,765	$31,852
Wygen III	$136,220	$29	$13,811
Busch Ranch Wind Project	$18,590	$—	$1,573

(4) BUSINESS SEGMENTS INFORMATION

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. Primarily, all of our operations and assets are located within the United States.

On February 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being reclassified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been reclassified as discontinued operations have been reclassified to our Corporate segment. For further information see Note 21.

Segment information was as follows (in thousands):

Total Assets (net of inter-company eliminations) as of December 31,	2014	2013
Utilities:		
Electric [(a)]	$2,748,680	$2,525,947
Gas	906,922	805,617
Non-regulated Energy:		
Power Generation [(a)]	76,945	95,692
Coal Mining	74,407	78,825
Oil and Gas	332,343	251,124
Corporate	106,605	80,731
Total assets	$4,245,902	$3,837,936

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power

Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Capital Expenditures and Asset Acquisitions[a] for the years ended December 31,	2014	2013
Utilities:		
Electric Utilities	$193,199	$222,262
Gas Utilities	70,528	63,205
Non-regulated Energy:		
Power Generation	2,379	13,533
Coal Mining	6,676	5,528
Oil and Gas	109,439	64,687
Corporate	9,046	10,319
Total capital expenditures and asset acquisitions	$391,267	$379,534

(a) Includes accruals for property, plant and equipment.

Property, Plant and Equipment as of December 31,	2014	2013
Utilities:		
Electric Utilities [a]	$2,597,212	$2,464,603
Gas Utilities	687,665	627,573
Non-regulated Energy:		
Power Generation [a]	156,041	153,517
Coal Mining	149,367	150,223
Oil and Gas	962,395	852,384
Corporate	10,720	11,145
Total property, plant and equipment	$4,563,400	$4,259,445

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Consolidating Income Statement

Year ended December 31, 2014	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$683,201	$617,768	$6,401	$31,086	$55,114	$—	$—	$1,393,570
Inter-company revenue	14,110	—	81,157	32,272	—	222,460	(349,999)	—
Total revenue	697,311	617,768	87,558	63,358	55,114	222,460	(349,999)	1,393,570
Fuel, purchased power and cost of natural gas sold	314,573	380,852	—	—	—	116	(113,759)	581,782
Operations and maintenance	165,641	132,635	33,126	41,172	42,659	213,415	(225,473)	403,175
Depreciation, depletion and amortization	79,424	26,499	4,540	10,276	24,246	7,690	(7,930)	144,745
Operating income (loss)	137,673	77,782	49,892	11,910	(11,791)	1,239	(2,837)	263,868
Interest expense	(53,402)	(15,725)	(4,351)	(493)	(2,603)	(50,299)	55,913	(70,960)
Interest income	4,615	441	682	59	918	48,969	(53,759)	1,925
Other income (expense), net	1,164	34	(6)	2,275	183	61,605	(62,574)	2,681
	(30,498)	(20,663)	(17,701)	(3,299)	4,768	24	744	(66,625)

Income tax benefit (expense)								
Income (loss) from continuing operations	$59,552	$41,869	$28,516	$10,452	$(8,525)	$61,538	$(62,513)	$130,889

81

Year ended December 31, 2013	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$651,445	$539,689	$4,648	$25,186	$54,884	$—	$—	$1,275,852
Inter-company revenue	13,863	—	78,389	31,442	—	220,620	(344,314)	—
Total revenue	665,308	539,689	83,037	56,628	54,884	220,620	(344,314)	1,275,852
Fuel, purchased power and cost of natural gas sold	294,048	310,463	—	—	—	125	(112,489)	492,147
Operations and maintenance	159,961	126,073	30,186	39,519	40,365	202,809	(211,977)	386,936
Depreciation, depletion and amortization	77,704	26,381	5,091	11,523	17,877	11,624	(12,876)	137,324
Operating income (loss)	133,595	76,772	47,760	5,586	(3,358)	6,062	(6,972)	259,445
Interest expense [a]	(61,537)	(25,234)	(21,178)	(641)	(2,253)	(85,195)	84,250	(111,788)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	30,169	—	30,169
Interest income	5,277	976	785	10	1,639	69,760	(76,724)	1,723
Other income (expense), net	633	(60)	1	2,304	108	41,453	(42,641)	1,798
Income tax benefit (expense)	(25,834)	(19,747)	(11,080)	(932)	2,113	(7,778)	218	(63,040)
Income (loss) from continuing operations	$52,134	$32,707	$16,288	$6,327	$(1,751)	$54,471	$(41,869)	$118,307

(a) Power Generation includes costs associated with interest rate swaps settled and write-off of deferred financing costs upon repayment of Black Hills Wyoming Project Financing and Corporate includes a write-off of deferred financing costs and a make-whole provision from early repayment of long-term debt (see Note 5).

Year ended December 31, 2012	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$610,732	$454,081	$4,189	$25,810	$79,072	$—	$—	$1,173,884
Inter-company revenue	16,234	—	75,200	31,968	—	196,453	(319,855)	—
Total revenue	626,966	454,081	79,389	57,778	79,072	196,453	(319,855)	1,173,884
Fuel, purchased power and cost of natural gas sold	273,474	245,349	—	—	—	—	(111,757)	407,066
Operations and maintenance	146,527	117,390	29,991	42,553	43,267	179,059	(188,051)	370,736
Gain on sale of operating assets [(a)]	—	—	—	—	(75,854)	—	—	(75,854)
Depreciation, depletion and amortization	75,244	25,163	4,599	13,060	29,785	10,936	(12,864)	145,923
Impairment of long-lived assets[(b)]	—	—	—	—	49,571	—	—	49,571
Operating income (loss)	131,721	66,179	44,799	2,165	32,303	6,458	(7,183)	276,442
Interest expense[(c)]	(59,194)	(26,746)	(15,452)	(238)	(4,539)	(92,650)	85,209	(113,610)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	1,882	—	1,882
Interest income	8,153	2,765	695	1,168	604	64,695	(76,123)	1,957
Other income (expense), net	1,182	105	7	2,616	207	48,769	(49,921)	2,965
Income tax benefit (expense)	(30,264)	(14,313)	(8,721)	(85)	(9,892)	3,187	(131)	(60,219)
Income (loss) from continuing operations	$51,598	$27,990	$21,328	$5,626	$18,683	$32,341	$(48,149)	$109,417

(a) Oil and Gas includes gain on sale of the Williston Basin assets (see Note 21).
(b) Oil and Gas includes a ceiling test impairment (see Note 12).
(c) Corporate includes a make-whole provision from early repayment of long-term debt.

83

(5) LONG-TERM DEBT

Long-term debt outstanding was as follows (dollars in thousands) as of:

	Due Date	Interest Rate at December 31, 2014	December 31, 2014	December 31, 2013
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$525,000	$525,000
Unamortized discount on Senior unsecured note due 2023 (a)			(2,164)	—
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Corporate term loan due 2015 (b)	June 19, 2015	1.31%	275,000	275,000
Total Corporate Debt			997,836	1,000,000
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	—
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	—
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
Unamortized discount on First Mortgage Bonds due 2039			(102)	(107)
Pollution control revenue bonds due 2024	October 1, 2024	5.35%	—	12,200
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021, variable rate (c)	September 1, 2021	0.09%	7,000	7,000
Industrial development revenue bonds due 2027, variable rate (c)	March 1, 2027	0.09%	10,000	10,000
Series 94A Debt, variable rate (c)	June 1, 2024	0.75%	2,855	2,855
Total Electric Utilities			544,753	396,948
Total long-term debt			1,542,589	1,396,948
Less current maturities			275,000	—
Long-term debt, net of current maturities			$1,267,589	$1,396,948

(a) Discount on note initially reflected in deferred financing costs at December 31, 2013.
(b) Variable interest rate, based on LIBOR plus a spread.
(c) Variable interest rate.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2015	$275,000
2016	$—
2017	$—
2018	$—
2019	$—

Thereafter	$1,269,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2014.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Debt Transactions

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044 and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35% $12 million pollution control revenue bonds, originally due October 1, 2024.

On November 19, 2013, we entered into a $525 million, 4.25% senior unsecured note expiring on November 30, 2023. The proceeds from this new debt were used to:

- Redeem our $250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest which are included in Interest expense on the accompanying Consolidated Statements of Income;
- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of approximately $87 million originally due on December 9, 2016, as well as the interest rate swaps designated to this project financing of $8.5 million which is included in Interest expense on the accompanying Consolidated Statements of Income;
- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million;
- Pay down approximately $55 million of the Revolving Credit Facility; and
- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new long-term Corporate Term Loan for $275 million expiring on June 19, 2015. The proceeds from this new term loan were used to repay the $150 million corporate term loan due on June 24, 2013, the $100 million corporate term loan due on September 30, 2013 and approximately $25 million in short-term borrowing under our Revolving Credit Facility. The covenants of the new term loan are substantially the same as the Revolving Credit Facility. At December 31, 2014, the cost of borrowing under this term loan was 1.3125% (LIBOR plus a margin of 1.125%).

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income were as follows (in thousands):

	Deferred Financing Costs Remaining in Other Assets, Non-current on Balance Sheets at	Amortization Expense for the years ended December 31,		
	December 31, 2014	2014	2013	2012
Senior unsecured notes due 2023	$3,908	$653	$86	$—
Senior unsecured notes due 2014	$—	$—	$635	$462
Senior unsecured notes due 2020	$926	$167	$167	$167
First mortgage bonds due 2044 (Black Hills Power) (a)	$711	$6	$—	$—

First mortgage bonds due 2044 (Cheyenne Light) [(a)]	$654	$6	$—	$—
First mortgage bonds due 2032	$584	$33	$33	$33
First mortgage bonds due 2039	$1,885	$76	$76	$76
First mortgage bonds due 2037	$705	$31	$31	$31
Black Hills Wyoming project financing due 2016 [(b)]	$—	$—	$3,177	$1,037
Other	$483	$53	$57	$57

(a) Deferred financing costs on Cheyenne Prairie first mortgage bonds executed on October 1, 2014.
(b) This project financing was repaid in 2013 and the deferred financing costs were written off.

85

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of December 31, 2014, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2014:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2014, the restricted net assets at our Utilities Group were approximately $315 million.

(6) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2014, we were in compliance with all of these financial covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	December 31, 2014	December 31, 2013
Revolving Credit Facility	$75,000	$82,500

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125% and 1.125%, respectively, from May 29, 2014 through December 31, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. Borrowings under the facility are primarily Eurodollar based. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

As of December 31, 2014 and 2013, we had outstanding letters of credit totaling approximately $35 million and approximately $22 million, respectively.

Deferred financing costs on the facility of $3.8 million are being amortized over the estimated useful life of the Revolving Credit Facility and included in Interest expense on the accompanying Consolidated Statements of Income. Upon entering into the Revolving Credit Facility in 2012, $1.5 million of deferred financing costs relating to the previous credit facility was written off through Interest expense. The deferred financing costs on the new facility are being amortized as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheets as of	Amortization Expense for the years ended December 31,		
	December 31, 2014	2014	2013	2012
Revolving Credit Facility	$1,779	$616	$752	$2,187

Debt Covenants

Our Revolving Credit Facility and our new Term Loan require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2014	Covenant Requirement
Recourse leverage ratio	55 %	Less than 65 %

(7) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in the Oil and Gas segment, reclamation of coal mining sites in the Coal Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment and asbestos at our regulated utilities segments. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following tables present the details of ARO which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2013	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates [a] [b]	December 31, 2014
Electric Utilities	$6,922	$—	$(85)	$175	$—	$7,012
Gas Utilities	274	—	—	17	—	291
Coal Mining	20,627	345	—	951	(2,785)	19,138
Oil and Gas	24,028	68	(932)	1,043	(3,262)	20,945
Total	$51,851	$413	$(1,017)	$2,186	$(6,047)	$47,386

	December 31, 2012	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	December 31, 2013
Electric Utilities	$6,981	$—	$—	$168	$(227)	$6,922
Gas Utilities	259	—	—	15	—	274
Coal Mining	20,286	3	(714)	1,052	—	20,627
Oil and Gas	23,022	143	(1,903)	1,450	1,316	24,028
Total	$50,548	$146	$(2,617)	$2,685	$1,089	$51,851

(a) The Coal Mining Revision to Prior Estimates reflects the change in backfill yards and disturbed acreage used in calculating the estimated liability.

(b) The Oil and Gas Revision to Prior Estimates was due to a change in useful well lives used in calculating the estimated liability.

We also have legally required AROs related to certain assets within our electric and gas utility transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a value for the cost of these obligations cannot be measured at this time.

(8) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt and our other short-term and long-term debt instruments.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

As of December 31, 2014, our credit exposure included a $0.6 million exposure to a non-investment grade rural electric cooperative. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 9.

Oil and Gas Exploration and Production

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue on the accompanying Consolidated Statements of Income (Loss).

The contract or notional amounts, terms of our commodity derivatives and the derivative balances for our Oil and Gas segment reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	December 31, 2014		December 31, 2013	
	Crude oil futures, swaps and options	Natural gas futures, swaps and options	Crude oil futures, swaps and options	Natural gas futures, swaps and options
Notional [(a)]	334,500	6,582,500	412,500	7,082,500
Maximum terms in months [(b)]	1	1	3	1
Derivative assets, current	$—	$—	$55	$—
Derivative assets, non-current	$—	$—	$—	$—
Derivative liabilities, current	$—	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—	$—

(a) Crude in Bbls, gas in MMBtu.

(b) Refers to the tenor of the derivative instrument. Assets and liabilities are classified as current/non-current based on the production month hedged and the corresponding settlement of the derivative instrument.

Based on December 31, 2014 market prices, a $10 million gain would be reclassified from AOCI during 2015. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required, by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income (Loss) or the Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Gas Utilities were as follows, as of:

	December 31, 2014		December 31, 2013	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	19,370,000	72	17,930,000	84
Natural gas options purchased	4,020,000	8	3,890,000	8
Natural gas basis swaps purchased	12,005,000	60	14,785,000	60

(a) Term reflects the maximum forward period hedged.

We had the following derivative balances related to the hedges in our Utilities reflected in our Consolidated Balance Sheets as of (in thousands):

	December 31, 2014	December 31, 2013
Derivative assets, current	$—	$662
Derivative assets, non-current	$—	$—
Derivative liabilities, current	$—	$—
Derivative liabilities, non-current	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$18,740	$7,567

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	December 31, 2014 Interest Rate Swaps [(a)]	December 31, 2013 Interest Rate Swaps [(a)]
Notional	$75,000	$75,000
Weighted average fixed interest rate	4.97 %	4.97 %
Maximum terms in years	2.0	3.0
Derivative liabilities, current	$3,340	$3,474
Derivative liabilities, non-current	$2,680	$5,614

(a) These swaps are designated to borrowings on our Revolving Credit Facility. These swaps are priced using three-month LIBOR, matching the floating portion of the related borrowings.

Based on December 31, 2014 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $3.3 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income (Loss) for years ended were as follows (in thousands):

	December 31, 2014				
Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(536)	Interest expense	$3,669		$—
Commodity derivatives	14,681	Revenue	1,995		—
Total	$14,145		$5,664		$—

Derivatives in Cash Flow Hedging Relationships	December 31, 2013 Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$7,935	Interest expense	$6,989		$—
Commodity derivatives	(956)	Revenue	(927)		—
Total	$6,979		$6,062		$—

Derivatives in Cash Flow Hedging Relationships	December 31, 2012 Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(4,794)	Interest expense	$(7,607)		$—
Commodity derivatives	2,639	Revenue	8,784		—
Total	$(2,155)		$1,177		$—

Derivatives Not Designated as Hedge Instruments

The impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended December 31 were as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	2014 Amount of Gain/(Loss) on Derivatives Recognized in Income	2013 Amount of Gain/(Loss) on Derivatives Recognized in Income	2012 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized (a)	Unrealized gain (loss) on interest rate swap, net	$—	$30,169	$1,882
Interest rate swaps - realized (a)	Interest expense	—	(12,902)	(12,959)
		$—	$17,267	$(11,077)

(a) These interest rate swaps were settled in the fourth quarter of 2013.

(9) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2014 or 2013. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 10. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

	As of December 31, 2014				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	8,599	—	(8,599)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	6,558	—	(6,558)	—
Commodity derivatives - Utilities	—	2,389	—	(2,389)	—
Total	$—	$17,546	$—	$(17,546)	$—
Liabilities:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	473	—	(473)	—
Commodity derivatives - Utilities	—	19,303	—	(19,303)	—
Interest rate swaps	—	6,020	—	—	6,020
Total	$—	$25,796	$—	$(19,776)	$6,020

	As of December 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	130	—	(75)	55
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	815	—	(815)	—
Commodity derivatives - Utilities	—	3,030	—	(2,368)	662
Total	$—	$3,975	$—	$(3,258)	$717
Liabilities:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	1,229	—	(1,229)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	531	—	(531)	—
Commodity derivatives - Utilities	—	9,100	—	(9,100)	—
Interest rate swaps	—	9,088	—	—	9,088
Total	$—	$19,948	$—	$(10,860)	$9,088

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis, aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions. However, the amounts do not include net cash collateral on deposit in margin accounts at December 31, 2014 and 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 8.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

	Balance Sheet Location	2014 Fair Value of Asset Derivatives	2014 Fair Value of Liability Derivatives	2013 Fair Value of Asset Derivatives	2013 Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Derivative assets - current	$10,391	$—	$248	$—
Commodity derivatives	Derivative assets - non-current	4,766	—	698	—
Commodity derivatives	Derivative liabilities - current	—	185	—	1,541
Commodity derivatives	Derivative liabilities - non-current	—	288	—	219
Interest rate swaps	Derivative liabilities - current	—	3,340	—	3,474
Interest rate swaps	Derivative liabilities - non-current	—	2,680	—	5,614
Total derivatives designated as hedges		$15,157	$6,493	$946	$10,848
Derivatives not designated as hedges:					
Commodity derivatives	Derivative assets - current	$—	$—	$662	$—
Commodity derivatives	Derivative assets - non-current	—	—	—	—
Commodity derivatives	Derivative liabilities - current	—	8,032	—	—
Commodity derivatives	Derivative liabilities - non-current	—	8,882	—	6,732
Interest rate swaps	Derivative liabilities - current	—	—	—	—
Interest rate swaps	Derivative liabilities - non-current	—	—	—	—
Total derivatives not designated as hedges		$—	$16,914	$662	$6,732

Derivatives Offsetting

It is our policy to offset in our Consolidated Balance Sheets contracts which provide for legally enforceable netting for our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at December 31, 2014 and December 31, 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at December 31, 2014 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$8,599	$(8,599)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	6,558	(6,558)	—
Utilities	2,389	(2,389)	—
Total derivative assets subject to a master netting agreement or similar arrangement	17,546	(17,546)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	—	—	—
Total derivative assets	$17,546	$(17,546)	$—

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$—	$—	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	473	(473)	—
Utilities	19,303	(19,303)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	19,776	(19,776)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Interest Rate Swaps	6,020	—	6,020
Total derivative liabilities not subject to a master netting agreement or similar arrangement	6,020	—	6,020
Total derivative liabilities	$25,796	$(19,776)	$6,020

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2013 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$75	$(75)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	815	(815)	—
Utilities	3,030	(2,368)	662
Total derivative assets subject to a master netting agreement or similar arrangement	3,920	(3,258)	662
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	55	—	55
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	55	—	55

Total derivative assets	$3,975	$(3,258)	$717

96

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$1,229	$(1,229)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	531	(531)	—
Utilities	9,100	(9,100)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	10,860	(10,860)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Interest Rate Swaps	9,088	—	9,088
Total derivative liabilities not subject to a master netting agreement or similar arrangement	9,088	—	9,088
Total derivative liabilities	$19,948	$(10,860)	$9,088

Derivative assets and derivative liabilities and collateral held by counterparty included in our Consolidated Balance Sheets as of December 31, 2014 were (in thousands):

Contract Type		Net Amount of Total Derivative Assets	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	—	—
		$—	$—	$—

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(4,392)	$(4,392)
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	(3,093)	(3,093)
Interest Rate Swaps	Counterparty F	6,020	—	6,020

	$6,020	$(7,485)	$(1,465)

97

Derivative assets and derivative liabilities and collateral held by counterparty included in our Consolidated Balance Sheets as of December 31, 2013 were (in thousands):

Contract Type		Net Amount of Total Derivative Assets	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	55	—	55
Utilities	Counterparty A	662	—	662
		$717	$—	$717

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(1,631)	$(1,631)
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	(3,390)	(3,390)
Interest Rate Swap	Counterparty F	9,088	—	9,088
		$9,088	$(5,021)	$4,067

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows at December 31 (in thousands):

	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$21,218	$21,218	$7,841	$7,841
Restricted cash and equivalents [(a)]	$2,056	$2,056	$2	$2
Notes payable [(a)]	$75,000	$75,000	$82,500	$82,500
Long-term debt, including current maturities [(b)]	$1,542,589	$1,734,555	$1,396,948	$1,491,422

(a) Carrying value approximates fair value due to either short-term length of maturity or variable interest rates that approximate prevailing market rates and therefore is classified in Level 1 in the fair value hierarchy.

(b) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, overnight repurchase agreement accounts, money market funds, and term deposits. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC, or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable and Long-Term Debt

For additional information on our notes payable and long-term debt, see Note 5 and Note 6.

(11) STOCK

Equity Compensation Plans

Our 2005 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 522,831 shares available to grant at December 31, 2014.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2014, total unrecognized compensation expense related to non-vested stock awards was approximately $9.4 million and is expected to be recognized over a weighted-average period of 1.6 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income was as follows for the years ended December 31 (in thousands):

	2014	2013	2012
Stock-based compensation expense	$9,329	$12,595	$8,271

Stock Options

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest proportionately over 3 years and expire 10 years after the grant date.

A summary of the status of the stock options at December 31, 2014 was as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at beginning of period	61	$ 33.25		
Granted [(a)]	81	54.29		
Forfeited/canceled	—	—		
Expired	—	—		
Exercised	(8)	30.87		
Balance at end of period	134	$ 46.12	8.2	$1,027
Exercisable at end of period	46	$ 32.63	6.5	$944

(a) The grant date fair value of the 2014 awards was $12.58 based on a Black-Scholes option pricing model. Assumptions used to estimate the fair value were a 2.1% risk free interest rate, 29.4% expected price volatility, 2.9% expected dividend yield and a 7 year expected life.

99

The table below provides details of our option plans at December 31 (in thousands):

	2014	2013	2012
Summary of Stock Options			
Unrecognized compensation expense	$816	$130	$218
Intrinsic value of options exercised [(a)]	$199	$789	$623
Net cash received from exercise of options	$237	$2,046	$2,839
Tax benefit realized from exercise of shares [(b)]	$70	$276	$218

(a) The intrinsic value represents the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option.
(b) The tax benefit realized from the exercise of shares granted was recorded as an increase in equity.

As of December 31, 2014, the unrecognized compensation expense related to non-vested stock options is expected to be recognized over a weighted-average period of 2.1 years.

Restricted Stock

The fair value of restricted stock awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock at December 31, 2014, was as follows:

	Restricted Stock (in thousands)	Weighted-Average Grant Date Fair Value
Restricted Stock at beginning of period	262	$36.76
Granted	99	54.34
Vested	(114)	35.25
Forfeited	(14)	43.17
Restricted Stock at end of period	233	$44.60

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended December 31, was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2014	$54.34	$6,114
2013	$40.56	$5,842
2012	$34.99	$3,781

As of December 31, 2014, there was $6.1 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 1.7 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.1 million at December 31, 2014 would be reclassified as a liability.

Outstanding performance periods at December 31 were as follows (shares in thousands):

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2012	January 1, 2012 - December 31, 2014	64	0%	200%
January 1, 2013	January 1, 2013 - December 31, 2015	61	0%	200%
January 1, 2014	January 1, 2014 - December 31, 2016	44	0%	200%

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value [(a)]	Shares (in thousands)	Weighted-Average Fair Value at [(b)] December 31, 2014
Performance Shares balance at beginning of period	93	$31.34	93	
Granted	23	55.18	23	
Forfeited	(1)	40.12	(1)	
Vested	(31)	25.92	(31)	
Performance Shares balance at end of period	84	$39.58	84	$82.42

(a) The grant date fair values for the performance shares granted in 2014, 2013 and 2012 were determined by Monte Carlo simulation using a blended volatility of 23%, 20% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

(b) The weighted-average fair value for the liability portion at December 31, 2014 was determined by the actual performance for the 2012 to 2014 performance period at the top of the peer group resulting in a 200% of target payout, and determined by Monte Carlo simulations for the 2013 to 2015 performance period and 2014 to 2016 performance period projecting a 157% and 51% of target payouts, respectively.

The weighted-average grant-date fair value of performance share awards granted in the years ended was as follows:

	Weighted Average Grant Date Fair Value
December 31, 2014	$55.18
December 31, 2013	$35.85
December 31, 2012	$32.26

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Shares Issued	Cash Paid	Total Intrinsic Value
January 1, 2011 to December 31, 2013	2014	59	$3,011	$6,020
January 1, 2010 to December 31, 2012	2013	63	$2,267	$4,533
January 1, 2009 to December 31, 2011	2012	—	$—	$—

On January 27, 2015, the Compensation Committee of our Board of Directors determined that the Company's total shareholder return for the January 1, 2012 through December 31, 2014 performance period was at the 100th percentile of its peer group and confirmed a payout equal to 200% of target shares, valued at $7.3 million. The payout was fully accrued at December 31, 2014.

As of December 31, 2014, there was $2.5 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.5 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We are currently issuing new shares.

A summary of the DRSPP for the years ended December 31 is as follows (shares in thousands):

	2014	2013
Shares Issued	52	67
Weighted Average Price	$54.99	$46.78
Unissued Shares Available	474	286

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

(12) IMPAIRMENT OF LONG-LIVED ASSETS

Under the full cost method of accounting used by our Oil and Gas segment to account for exploration, development and acquisition of crude oil and natural gas reserves, all costs attributable to these activities are capitalized. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties. Any costs in excess of the ceiling are written off as a non-cash charge.

As a result of continued low commodity prices in the second quarter of 2012, we recorded a $50 million non-cash impairment of oil and gas assets included in the Oil and Gas segment. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. When this non-cash impairment occurred, commodity prices during the second quarter of 2012 were; for natural gas, the average NYMEX price was $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead; for crude oil, the average NYMEX price was $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead.

(13) OPERATING LEASES

We have entered into lease agreements for vehicles, equipment and office facilities. Rental expense incurred under these operating leases, including month to month leases, for the years ended December 31 was as follows (in thousands):

	2014	2013	2012
Rent expense	$6,932	$7,169	$6,839

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2015	$9,962
2016	$2,045
2017	$1,852
2018	$1,829
2019	$1,632
Thereafter	$3,735

(14) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2014	2013	2012
Current:			
Federal	$(2,319)	$(2,003)	$4,972
State	(1,288)	(173)	3,712
	(3,607)	(2,176)	8,684
Deferred:			
Federal	64,780	58,288	51,363
State	5,658	7,140	400
Tax credit amortization	(206)	(212)	(228)
	70,232	65,216	51,535
	$66,625	$63,040	$60,219

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2014	2013
Deferred tax assets:		
Regulatory liabilities	$49,243	$33,172
Employee benefits	26,714	28,724
Federal net operating loss	213,466	166,095
Asset impairment [(a)]	93,663	93,830
Other deferred tax assets [(b)]	76,005	59,078
Less: Valuation allowance	(5,017)	(1,806)
Total deferred tax assets	454,074	379,093
Deferred tax liabilities:		
Accelerated depreciation, amortization and other plant-related differences	(695,280)	(613,827)
Regulatory assets	(25,340)	(24,581)
Mining development and oil exploration	(109,571)	(81,069)
State deferred tax liability	(36,579)	(29,322)
Deferred costs	(35,284)	(15,593)
Other deferred tax liabilities	(15,684)	(15,104)
Total deferred tax liabilities	(917,738)	(779,496)
Net deferred tax liability	$(463,664)	$(400,403)

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(a) Majority of impairment deferred tax asset is related to oil and gas properties.

(b) Other deferred tax assets consist primarily of state tax credits, state net operating loss, alternative minimum tax credit and federal research and development credits. No single item exceeds 5% of the total net deferred tax liability.

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2014		2013		2012	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State income tax (net of federal tax effect)	1.1		2.4		1.8	
Amortization of excess deferred income taxes and investment tax credits	(0.1	)	(0.1	)	(0.1	)
Percentage depletion in excess of cost	(1.0	)	(0.9	)	(1.0	)
Equity AFUDC	(0.1	)	—		—	
Tax credits	(0.1	)	(0.5	)	—	
Accounting for uncertain tax positions adjustment	(0.1	)	0.7		0.6	
Flow-through adjustments [(a)]	(0.9	)	(0.9	)	(1.0	)
Other tax differences	(0.1	)	(0.9	)	0.2	
	33.7	%	34.8	%	35.5	%

(a) The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred in 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow-through method.

At December 31, 2014, we have federal and gross state NOL carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates		
Federal Net Operating Loss Carryforward	$618,195	2019	to	2034
State Net Operating Loss Carryforward	$513,418	2015	to	2034

As of December 31, 2014, we had a $1.0 million valuation allowance against the state NOL carryforwards. Our 2014 analysis of the ability to utilize such NOLs resulted in an increase of the valuation allowance of approximately $0.5 million, which resulted in an increase to tax expense. The valuation allowance adjustment was primarily attributable to a decrease in taxable income for 2014 due to the enactment of TIPA. Such a decrease impacted the utilization of NOL carryforward in those states where the carryforward period is significantly shorter than the federal carryforward period of 20 years. In certain states, the carryforward period is limited to 5 years. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	Changes in Uncertain Tax Positions
Beginning balance at January 1, 2012	$49,327
Additions for prior year tax positions	111
Reductions for prior year tax positions	(8,906)
Additions for current year tax positions	151
Settlements	—
Ending balance at December 31, 2012	40,683
Additions for prior year tax positions	1,526
Reductions for prior year tax positions	(4,578)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2013	37,631
Additions for prior year tax positions	1,253
Reductions for prior year tax positions	(6,692)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2014	$32,192

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $1.8 million.

We recognized interest expense of $1.6 million, $1.6 million and $1.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

We had approximately $11.5 million and $9.9 million of accrued interest (before tax effect) associated with income taxes at December 31, 2014 and 2013, respectively.

We file income tax returns with the IRS and various state jurisdictions. We received a 30-day Letter along with a Revenue Agent's Report from the IRS in regards to the audit of the 2007 to 2009 tax years. A protest was timely filed with IRS in August 2014 related to the like-kind exchange transaction described below and research and development credits and deductions claimed with respect to certain costs and projects. We are also currently under examination by the IRS for the 2010 to 2012 tax years.

We have deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes attributable to the like-kind exchange effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. The IRS has challenged our position with respect to the like-kind exchange and it is reasonably possible that the total unrecognized tax benefits attributable to such transaction could change significantly due to a settlement with the IRS that is anticipated to occur on or before December 31, 2015. However, based on the information currently available, it is difficult to determine any reasonable estimate of the financial statement impact including the impact on the effective tax rate.

Excess foreign tax credits have been generated and are available to offset United States federal income taxes. At December 31, 2014, we had foreign tax credit carryforwards of approximately $0.5 million, which expire between 2015 and 2017.

As of December 31, 2014, we had a $0.5 million valuation allowance against the foreign tax credit carryforwards. In addition, the carryforward balance reflects the expected utilization of approximately $1.8 million of foreign tax credits to be included as computational adjustments upon finalization of our current IRS examination covering tax years 2007 to 2009. Such foreign tax credits have been reflected as an offset to liabilities for unrecognized tax benefits in recognition of the estimated impact the resolution of material uncertain tax positions could have with respect to utilization.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2014, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards		Expiration Year		
Investment tax credit	$14,793	2023	to	2025
Research and development	$155	No expiration		

As of December 31, 2014, we had a $3.5 million valuation allowance against the state tax credit carryforwards. The re-evaluation of our ability to utilize such credits resulted in an increase of the valuation allowance of approximately $2.7 million of which approximately $1.5 million resulted in an increase to tax expense. The remaining $1.2 million increase is attributable to our regulated business and is being accounted for under the deferral method whereby the credits are amortized to tax expense over the estimated useful life of the underlying asset that generated the credit. The valuation allowance adjustment was primarily attributable to the projected impact of lower commodity prices related to oil and natural gas on forecasted taxable income. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(15) OTHER COMPREHENSIVE INCOME

The components of the reclassification adjustments for the period, net of tax, included in Other comprehensive income were as follows (in thousands):

	Location on the Consolidated Statements of Income	Amount Reclassified from AOCI December 31, 2014	December 31, 2013
Gains and losses on cash flow hedges:			
Interest rate swaps	Interest expense	$3,669	$6,989
Commodity contracts	Revenue	1,995	(927)
		5,664	6,062
Income tax	Income tax benefit (expense)	(2,344)	(2,016)
Total reclassification adjustments related to cash flow hedges, net of tax		$3,320	$4,046
Amortization of defined benefit plans:			
Prior service cost	Utilities - Operations and maintenance	$(102)	$(125)
	Non-regulated energy operations and maintenance	(115)	(128)
Actuarial gain (loss)	Utilities - Operations and maintenance	630	1,693
	Non-regulated energy operations and maintenance	364	1,098
		777	2,538

Income tax	Income tax benefit (expense)	(272)	(883)
Total reclassification adjustments related to defined benefit plans, net of tax		$505	$1,655

107

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2013	$(6,625)	$(508)	$(10,289)	$(17,422)
Other comprehensive income (loss)	1,695	10,531	(9,848)	2,378
As of December 31, 2014	$(4,930)	$10,023	$(20,137)	$(15,044)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2012	$(16,313)	$600	$(19,775)	$(35,488)
Other comprehensive income (loss)	9,688	(1,108)	9,486	18,066
As of December 31, 2013	$(6,625)	$(508)	$(10,289)	$(17,422)

(16) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2014	2013	2012
	(in thousands)		
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$52,584	$59,811	$35,556
Increase (decrease) in capitalized assets associated with asset retirement obligations	$(5,634)	$1,235	$5,743
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$(69,239)	$(108,361)	$(116,593)
Income taxes, net	$(413)	$(4,573)	$(3,027)

108

(17) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis. The 401(k) Plan provides a Company Matching Contribution for all eligible participants and for certain eligible participants a Company Retirement Contribution based on the participant’s age and years of service. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

Funded Status of Benefit Plans

The funded status of postretirement benefit plans is required to be recognized in the statement of financial position. The funded status for pension plans is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation. Except for our regulated utilities, the unrecognized net periodic benefit cost is recorded within Accumulated other comprehensive income (loss), net of tax. For our regulated utilities, these costs are recoverable in our rates, and accordingly, the unrecognized net periodic benefit cost was alternatively recorded as a regulatory asset or regulatory liability, net of tax (see Note 1). The measurement date for all plans is December 31, 2014. As of December 31, 2014, the unfunded status of our Defined Benefit Pension Plans was $78 million; the unfunded status of our Supplemental Non-qualified Defined Benefit Plans was $41 million; and the unfunded status of our Non-pension Defined Benefit Postretirement Healthcare Plans was $44 million.

Defined Benefit Pension Plans (Pension Plans)

We have two defined benefit pension plans. Our BHC Pension Plan covers certain eligible employees of Black Hills Service Company, Black Hills Power, WRDC, BHEP and Cheyenne Light. The Black Hills Utility Holdings, Inc. Pension Plan covers certain eligible employees of Black Hills Energy. The benefits for the Pension Plans are based on years of service and calculations of average earnings during a specific time period prior to retirement. Both Pension Plans have been frozen to new employees and certain employees who did not meet age and service based criteria.

Pension Plan assets are held in a Master Trust. Each Plan holds an undivided interest in the Master Trust. Our Board of Directors has approved the Plans’ investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plans’ beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Plans’ benefit payment obligations. The Pension Plans’ assets consist primarily of equity, fixed income and hedged investments. The expected long-term rate of return for investments was 6.75% and 7.25% for the 2014 and 2013 plan years, respectively. Our Pension Plan funding policy is in accordance with the federal government’s funding requirements.

In 2011, the Cheyenne Light Pension Plan was amended to freeze the benefits of certain bargaining unit employees. This amendment was effective as of January 1, 2012. Additionally, effective October 1, 2012, the Cheyenne Light Pension Plan was merged into the BHC Pension Plan. The Pension Plan benefits are based on years of service and compensation levels.

Plan Assets

The percentages of total plan asset fair value by investment category for our Pension Plans at December 31 were as follows:

	2014		2013	
Equity	27	%	26	%
Real estate	5		4	
Fixed income	58		58	
Cash	2		1	
Hedge funds	8		11	
Total	100	%	100	%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor three retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans is pre-funded via VEBAs. Effective January 1, 2014, health care coverage for Medicare-eligible retirees will be provided through an individual market health care exchange for BHC and Black Hills Utility Holdings retirees.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Energy Plan provides for partial pre-funding via VEBAs. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees of Black Hills Energy located in the states of Kansas and Iowa. We do not pre-fund the Postretirement Healthcare Plans for those employees outside Kansas and Iowa.

Plan Contributions

Contributions to the Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Contributions for the years ended December 31 were as follows (in thousands):

	2014	2013
Defined Contribution Plan		
Company Retirement Contribution	$4,187	$2,775
Matching contributions - Defined Contribution Plans	$9,254	$8,524

	2014	2013
Defined Benefit Plans		

Defined Benefit Pension Plans	$10,200	$12,500
Non-Pension Defined Benefit Postretirement Healthcare Plans	$3,163	$5,123
Supplemental Non-Qualified Defined Benefit Plans	$1,553	$1,345

While we do not have required contributions, we expect to make approximately $10 million in contributions to our Defined Benefit Pension Plans in 2015.

Fair Value Measurements

As required by accounting standards for Compensation - Retirement Benefits, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Defined Benefit Pension Plans	December 31, 2014			
	Level 1	Level 2	Level 3	Total
AXA Equitable General Fixed Income	$—	$541	$—	$541
Common Collective Trust - Cash and Cash Equivalents	—	4,013	—	4,013
Common Collective Trust - Equity	—	81,636	—	81,636
Common Collective Trust - Fixed Income	—	174,726	—	174,726
Common Collective Trust - Real Estate	—	3,864	9,719	13,583
Hedge Funds	—	—	25,034	25,034
Total investments measured at fair value	$—	$264,780	$34,753	$299,533

Defined Benefit Pension Plans	December 31, 2013			
	Level 1	Level 2	Level 3	Total
AXA Equitable General Fixed Income	$—	$1,056	$—	$1,056
Common Collective Trust - Cash and Cash Equivalents	—	1,253	—	1,253
Common Collective Trust - Equity	—	73,726	—	73,726
Common Collective Trust - Fixed Income	—	162,747	—	162,747
Common Collective Trust - Real Estate	—	3,392	8,541	11,933
Hedge Funds	—	—	29,647	29,647
Total investments measured at fair value	$—	$242,174	$38,188	$280,362

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Registered Investment Company Trust - Money Market Mutual Fund	$—	$4,705	$—	$4,705
Total investments measured at fair value	$—	4,705	$—	$4,705

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Registered Investment Company Trust - Money Market Mutual Fund	$—	$4,546	$—	$4,546
Total investments measured at fair value	$—	$4,546	$—	$4,546

The following table sets forth a summary of changes in the fair value of the Defined Benefit Pension Plans' Level 3 assets for the period ended December 31 (in thousands):

	2014	2013
Balance, beginning of period	$38,188	$7,770
Purchase	454	29,000
Unrealized gain (loss)	1,789	1,508
Realized gain (loss)	322	(77)
Settlements	(6,000)	(13)
Balance, end of period	$34,753	$38,188

The following table presents the quantitative information about Level 3 fair value measurements (dollars in thousands):

	Fair Value at December 31, 2014	Valuation Technique	Level 3 Input	Range (Weighted) Average
Assets:				
Common Collective Trust - Real Estate [(a)]	$9,719	Market Approach	Redemption Restriction	N/A
Hedge Funds [(b)]	$25,034	Market Approach	Redemption Restriction	N/A

(a) The underlying net asset value in the Common Collective Trust - Real Estate fund is determined by appraisal of the properties held in the Trust. As part of the Trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with the professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the Trustee along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The fund does contain a participant withdrawal policy.

(b) The fair value of the Hedge Funds is determined based on pricing provided or reviewed by the third-party administrator to our investment managers. While the input amounts used by the pricing vendor in determining fair value are not provided, and therefore, unavailable for our review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar asset classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

Additional information about assets of the Pension Plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately place bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates at which loans with similar characteristics have. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

Common Collective Trust-Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments, and rely on these reports for pricing the units of the fund. Certain of the funds' assets contain participant withdrawal policy and, therefore, are categorized as Level 3. The funds without participant withdrawal limitations are categorized as Level 2.

Hedge Funds: Hedge funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter, with a 65 day notice and are limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds. The Plan's investment in the hedge fund is categorized as Level 3.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the statement of financial position, components of the net periodic expense and elements of accumulated other comprehensive income (in thousands):

Benefit Obligations

		Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
		2014	2013	2014	2013	2014	2013
Change in benefit obligation:							
Projected benefit obligation at beginning of year		$321,400	363,235	$32,960	$34,393	$45,778	$46,681
Service cost		5,448	6,433	2,543	1,392	1,700	1,674
Interest cost		15,852	15,300	1,447	1,328	1,919	1,669
Actuarial (gain) loss	(a)	55,384	(38,252)	5,814	(2,808)	2,275	(3,379)
Amendments (b)		—	—	—	—	—	1,585
Benefits paid	(c)	(20,312)	(25,316)	(1,553)	(1,345)	(3,163)	(5,123)
Medicare Part D accrued		—	—	—	—	(99)	470
Plan participants' contributions		—	—	—	—	632	2,201
Projected benefit obligation at end of year		$377,772	$321,400	$41,211	$32,960	$49,042	$45,778

(a) Change from 2013 reflects a decrease in the discount rate and a change in the mortality tables used in employee benefit plan estimates.

(b) Reflects Board of Directors approval of an increase to Company's contribution to RMSA accounts.

(c) Benefits paid include payments made to terminated vested employees who elected lump-sum offerings of $6.1 million in 2014 and $13 million in 2013.

A reconciliation of the fair value of Plan assets was as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans [a]	
	2014	2013	2014	2013	2014	2013
Beginning market value of plan assets	$280,362	$268,816	$—	$—	$4,546	$4,351
Investment income (loss)	29,283	24,362	—	—	(43)	8
Employer contributions	10,200	12,500	—	—	2,733	1,923
Retiree contributions	—	—	—	—	632	1,533
Benefits paid	(20,312)	(25,316) [b]	—	—	(3,163)	(3,269)
Plan administrative expenses	—	—	—	—	—	—
Ending market value of plan assets	$299,533	$280,362	$—	$—	$4,705	$4,546

(a) Assets of VEBA.

(b) Benefits paid include payments made to terminated vested employees who elected a lump-sum offering of $6.1 million in 2014 and $13 million in 2013.

Amounts recognized in the Consolidated Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2014	2013	2014	2013	2014	2013
Regulatory assets	$78,864	$48,419	$—	$—	$7,137	$5,535
Current liabilities	$—	$—	$1,486	$1,491	$3,273	$2,802
Non-current liabilities	$78,239	$41,034	$39,725	$32,033	$41,002	$38,412
Regulatory liabilities	$—	$—	$—	$—	$2,983	$3,141

Accumulated Benefit Obligation

(in thousands)	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2014	2013	2014	2013	2014	2013
Accumulated benefit obligation - Black Hills Corporation	$135,582	$110,847	$29,843	$27,380	$12,809	$12,101
Accumulated benefit obligation - Black Hills Energy	213,398	182,295	386	513	25,456	25,467
Accumulated benefit obligation - Cheyenne Light	—	—	—	—	10,777	8,210
Total Accumulated Benefit Obligation	$348,980	$293,142	$30,229	$27,893	$49,042	$45,778

Components of Net Periodic Expense

(in thousands)	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Service cost	$5,448	$6,433	$5,720	$1,498	$1,392	$889	$1,700	$1,674	$1,610
Interest cost	15,852	15,300	14,747	1,447	1,328	1,410	1,919	1,669	2,093
Expected return on assets	(18,065)	(18,615)	(16,334)	—	—	—	(85)	(79)	(78)
Amortization of prior service cost	62	63	89	2	2	3	(428)	(500)	(500)
Recognized net actuarial loss (gain)	4,806	12,250	9,630	498	793	807	160	482	887
Net periodic expense	$8,103	$15,431	$13,852	$3,445	$3,515	$3,109	$3,266	$3,246	$4,012

Accumulated Other Comprehensive Income

In accordance with accounting standards for defined benefit plans, amounts included in Accumulated other comprehensive income (loss), after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2014	2013	2014	2013	2014	2013
Net (gain) loss	$10,996	$4,842	$8,396	$4,939	$1,904	$1,648
Prior service cost (gain)	51	64	8	9	(1,218)	(1,213)
Total accumulated other comprehensive (income) loss	$11,047	$4,906	$8,404	$4,948	$686	$435

The amounts in Accumulated other comprehensive income (loss), Regulatory assets or Regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2015 are as follows (in thousands):

	Defined Benefit Pension Plans	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plans
Net loss	$7,174	$703	$295
Prior service cost (credit)	38	1	(278)
Total net periodic benefit cost expected to be recognized during calendar year 2015	$7,212	$704	$17

Assumptions

	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine benefit obligations:	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate	4.20%	5.05%	4.30%	3.64%	4.21%	3.44%	3.92%	4.62%	3.85%

Rate of increase in compensation levels	3.78 %	3.78 %	3.84 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

115

	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate:									
Black Hills Corporation	5.10%	4.35%	4.68%	4.68%	3.88%	4.70%	4.45%	3.65%	4.35%
Black Hills Energy	5.00%	4.25%	4.60%	3.75%	3.00%	3.90%	4.25%	3.50%	4.35%
Cheyenne Light	N/A	N/A	N/A	N/A	N/A	N/A	5.15%	4.40%	4.65%
Expected long-term rate of return on assets [(a)]	6.75%	7.25%	7.25%	N/A	N/A	N/A	2.00%	2.00%	2.00%
Rate of increase in compensation levels	3.78%	3.78%	3.75%	5.00%	5.00%	5.00%	N/A	N/A	N/A

(a) The expected rate of return on plan assets is 6.75% for the calculation of the 2015 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	Black Hills Corporation	Black Hills Energy	Cheyenne Light
2014			
Healthcare trend rate pre-65			
Trend for next year	7.50%	7.50%	7.50%
Ultimate trend rate	4.50%	4.50%	4.50%
Year Ultimate Trend Reached	2027	2027	2027
Healthcare trend rate post-65			
Trend for next year	6.25%	6.25%	6.25%
Ultimate trend rate	4.50%	4.50%	4.50%
Year Ultimate Trend Reached	2024	2024	2024
2013			
Healthcare trend rate pre-65			
Trend for next year	7.50%	7.50%	7.50%
Ultimate trend rate	4.50%	4.50%	4.50%
Year Ultimate Trend Reached	2027	2027	2027
Healthcare trend rate post-65			
Trend for next year	6.25%	6.25%	6.25%
Ultimate trend rate	4.50%	4.50%	4.50%
Year Ultimate Trend Reached	2026	2026	2026

We do not pre-fund our non-qualified pension plans or two of the three postretirement benefit plans. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2014 Accumulated Postretirement Benefit Obligation	Impact on 2014 Service and Interest Cost
Increase 1%	$2,635	$168
Decrease 1%	$(2,166)	$(136)

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plans	Supplemental Non-qualified Defined Benefit Plan	Non-Pension Defined Benefit Postretirement Healthcare Plans
2015	$14,712	$1,486	$3,921
2016	$15,629	$1,573	$4,011
2017	$16,561	$1,627	$4,057
2018	$17,556	$1,670	$4,169
2019	$18,741	$1,780	$4,236
2020-2024	$109,147	$8,901	$19,877

(18) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts with non-affiliated third-parties:

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- Black Hills Power's PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.

- Black Hills Power has a firm point-to-point transmission service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- Cheyenne Light's PPA with Duke Energy's Happy Jack wind site, expiring September 3, 2028, provides up to 30 MW of wind energy from Happy Jack to Cheyenne Light. Under a separate inter-company agreement, Cheyenne Light sells 50% of the facility output to Black Hills Power.

- Cheyenne Light's PPA with Duke Energy's Silver Sage wind site, expiring September 30, 2029, provides up to 30 MW of wind energy. Under a separate inter-company agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

- Colorado Electric's PPA with Cargill expiring on December 31, 2015, which provides for the purchase of 50 MW energy during heavy load timing intervals.

- Colorado Electric's PPA with Cargill expiring on December 31, 2016, which provides for the purchase of 50 MW energy during light load timing intervals.

- Colorado Electric’s REPA with AltaGas expiring October 16, 2037, provides up to 14.5 MW of wind energy from the Busch Ranch Wind Project in which Colorado Electric owns a 50% undivided ownership interest.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2014	2013	2012
PPA with PacifiCorp	$13,943	$13,026	$13,224
Transmission services agreement with PacifiCorp	$1,227	$1,384	$1,215
PPA with Happy Jack	$3,919	$3,772	$1,988
PPA with Silver Sage	$4,798	$4,809	$3,269
Busch Ranch Wind Project	$1,998	$1,856	$502
PPAs with Cargill [(a)]	$9,286	$12,291	$14,236

(a) The 2013 and 2012 PPAs were one year contracts replaced by subsequent one year contracts upon expiration.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation capacity to meet customers’ needs, under short-term and long-term purchase contracts. These contracts extend to 2017.

Natural Gas Delivery Commitment

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. This take or pay contract requires us to pay the fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. The ten-year agreement expiring in 2024 became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes.

Future Minimum Payments

The following is a schedule of future minimum payments required under the power purchase, transmission services, coal and gas supply agreements and natural gas delivery commitments (in thousands):

2015	$183,116
2016	$131,716
2017	$121,867
2018	$69,000
2019	$35,905
Thereafter	$153,395

Future Purchase Agreement - Related Party

Cheyenne Light’s PPA for 60 MW of capacity and energy from Black Hills Wyoming’s Wygen I generating facility expiring on December 31, 2022, includes an option for Cheyenne Light to purchase Black Hills Wyoming’s ownership in the
Wygen I facility. The purchase price related to the option is $2.6 million per MW which is the equivalent per MW of the pre-construction estimated cost of the Wygen III plant, which was completed in April 2010. This option purchase price is adjusted for capital additions and reduced by an amount equal to annual depreciation based on a 35-year life starting January 1, 2009.

Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU.

- Black Hills Power has an agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette their operating component of spinning reserves.

- Black Hills Power has a PPA with MEAN expiring April 1, 2015. Under this contract, MEAN purchases 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

- Black Hills Power has a PPA with MEAN expiring May 31, 2023. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

Purchase Commitment

On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc. for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory. This purchase is expected to be completed in 2015.

Related Party Lease

Colorado Electric’s PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP’s combined-cycle turbines. This PPA is accounted for as a capital lease whereby Colorado Electric, as lessee, has included the combined-cycle turbines as property, plant and equipment along with the related lease obligation and Black Hills Colorado IPP, as lessor, has recorded a lease receivable. Segment revenue and expenses associated with the PPA have been impacted by the lease accounting. The effect of the lease accounting is eliminated in corporate consolidations.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Cheyenne Light for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Cheyenne Light’s Letter of Credit attached to these bonds.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Air

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NO_x, mercury particulate matter and GHG. Power generating facilities burning fossil fuels emit each of the foregoing pollutants and, therefore, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Title IV of the Clean Air Act applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen I, Wygen II, Wygen III, Wyodak and Pueblo Airport Generating Station plants. Title IV of the Clean Air Act created an SO_2 allowance trading program as part of the federal acid rain program. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2044.

The EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, with updates which impose emission limits, fuel requirements and monitoring requirements. The rule had a compliance deadline of March 21, 2014. In anticipation of this rule we suspended operations at the Osage plant in October 2010 and as a result of this rule, we suspended operations at the Ben French facility on August 31, 2012. We permanently retired Ben French, Osage and Neil Simpson I on March 21, 2014. In conjunction with the Colorado Clean Air Clean Jobs Act, the CPUC issued an order approving the closure of the W.N. Clark facility no later than December 31, 2013. This facility suspended operations December 31, 2012 and was retired on December 31, 2013. The net book value of these plants was allowed regulatory accounting treatment and is recorded as a Regulatory Asset on the Consolidated Balance Sheet. The CPUC also approved a CPCN for the retirement of Pueblo Units #5 and #6 effective December 31, 2013.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years.

Our W.N. Clark plant, which has been retired, previously delivered coal ash to a permitted, privately-owned landfill. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond of $3.9 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its land lease for Busch Ranch, Colorado Electric is required to reclaim all land where it has placed wind turbines. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 7 for additional information.

Manufactured Gas Processing

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.3 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

In March 2011, Nebraska Gas executed an Allocation, Indemnification and Access Agreement with the successor to the former operator of the Nebraska MGPs. Under this agreement, Nebraska Gas agreed to remediate the Blair and Plattsmouth sites in Nebraska. Subsequent to this transaction, Nebraska Gas enrolled Blair and Plattsmouth in Nebraska's Voluntary Cleanup Program. Site remediation was completed in September 2012, however there is a potential for additional minimal remediation work at Plattsmouth where monitoring is required until 2015. Both Nebraska sites will be required to monitor groundwater quality for a minimum two year period, ending in 2015.

As of December 31, 2014, our estimated liabilities for all of the MGP sites currently range from approximately $2.7 million to $6.3 million for which we had $2.7 million accrued for remediation of sites as of December 31, 2014 included in Other deferred credits and other liabilities on our Consolidated Balance Sheets.

Prior to Black Hills Corporation's ownership, Aquila received rate orders that enabled recovery of environmental cleanup costs in certain jurisdictions. We anticipate recovery of these current and future costs would be allowed. Additionally, we may pursue recovery or agreements with other potentially responsible parties when and where permitted.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A fire investigator retained by the Weston County Fire Protection District concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power. On April 16, 2013, a large group of private landowners filed suit in the United States District Court for the District of Wyoming. There are approximately 36 Plaintiff groups (including property jointly owned by multiple family members or entities), or approximately 73 individually named private plaintiffs. In addition, the State of Wyoming has intervened in the lawsuit. Both the private landowners and the State of Wyoming assert claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance and trespass. In addition to claims for compensatory damages, the lawsuit seeks recovery of punitive damages. We have denied and will vigorously defend all claims arising out of the fire. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation.

Civil litigation of this kind, however, is likely to lead to settlement negotiations, including negotiations prompted by pre-trial civil court procedures. We believe such negotiations would effect a settlement of all claims. Regardless of whether the litigation is determined at trial or through settlement, we expect to incur significant investigation, legal and expert services expenses associated with the litigation. We maintain insurance coverage to limit our exposure to losses due to civil liability claims, and related litigation expense. We expect this coverage to limit our exposure and we will pursue recoveries to the maximum extent available under the policies. The deductible applicable to some types of claims arising out of this fire is $1.0 million. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, as of September 30, 2014, we recorded a loss contingency liability related to these claims and we recorded a receivable for costs we believe are reimbursable and probable of recovery under our insurance coverage. Both of these entries reflect our reasonable estimate of probable future litigation expense and settlement costs; we did not base these contingencies on any determination that it is probable we would be found liable for these claims were they to be litigated.

Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims in excess of the loss we have determined to be probable is reasonably possible. We cannot reasonably estimate the amount of such possible loss because our investigation and review of damage claims documentation is ongoing, and there are significant factual and legal issues to be resolved. Further claims may be presented by these claimants and other parties. We have received claims seeking recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate, currently totaling $55 million. We are not yet able to reasonably estimate the amount of any reasonable possible losses in excess of the amount we have accrued. Based upon information currently available, however, management does not expect the outcome of the claims to have a material adverse effect upon our consolidated financial condition, results of operations or cash flows.

(19) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2014	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$63,900	Ongoing

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

During the second quarter of 2014, guarantees of Black Hills Utility Holdings' payment obligations up to $70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

(20) OIL AND GAS RESERVES (Unaudited)

BHEP has operating and non-operating interests in 1,205 gross developed oil and gas wells in 10 states and holds leases on approximately 240,816 net acres.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

	2014	2013	2012
Acquisition of properties:			
Proved	$4,881	$234	$2,437
Unproved	5,056	6,022	33,052
Exploration costs	54,355	12,817	115
Development costs	52,262	48,641	73,877
Asset retirement obligations incurred	68	143	158
Total costs incurred	$116,622	$67,857	$109,639

Reserves

The following table summarizes BHEP's quantities of proved developed and undeveloped oil, natural gas and NGL reserves, estimated using SEC-defined product prices, as of December 31, 2014, 2013 and 2012 and a reconciliation of the changes between these dates. These estimates are based on reserve reports by CG&A. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

Minor differences in amounts may result in the following tables relating to oil and gas reserves due to rounding.

	2014			2013		2012	
	Oil	Gas	NGL	Oil	Gas	Oil	Gas
	(in Mbbls of oil and NGL, and MMcf of gas)						
Proved developed and undeveloped reserves:							
Balance at beginning of year	3,921	63,190	—	4,116	55,985	6,223	95,904
Production [(a)]	(337)	(7,156)	(135)	(336)	(6,984)	(560)	(8,686)
Additions - acquisitions (sales) [(b)]	(40)	(61)	—	(30)	(46)	(2,025)	(3,070)
Additions - extensions and discoveries	733	11,003	182	379	10,456	449	2,898
Revisions to previous estimates	(1)	(1,536)	1,673	(208)	3,779	29	(31,061)
Balance at end of year	4,276	65,440	1,720	3,921	63,190	4,116	55,985
Proved developed reserves at end of year included above	3,780	57,427	1,530	3,689	60,224	3,929	55,708
Proved undeveloped reserves at the end of year included in above	496	8,013	191	232	2,966	187	279
NYMEX prices	$94.99	$4.35	$— [(c)]	$96.94	$3.67	$94.71	$2.76
Well-head reserve prices	$85.80	$3.33	$34.81	$89.79	$3.45	$85.31	$2.24

(a) Production for reserve calculations does not include volumes for natural gas liquids (NGLs) for historical periods.
(b) Reflects the sale of the majority of the Williston Basin assets during 2012.
(c) A specific NYMEX price for NGL is not available. Market prices for NGL are broken down by various liquid components, including ethane, propane, iso butane, normal butane, and natural gasoline. Each of these components is traded as an index. Presently, ethane is not being recovered at any of the facilities that process our natural gas production.

Reserve additions totaled 16.5 Bcfe, replacing 165% of annual production. Reserve additions resulted from drilling in the Piceance, Powder River and Williston Basins. Drilling in the Piceance for Mancos Shale accounted for 12.3 Bcfe, Williston Basin (Bakken Shale) accounted for 0.5 Bcfe and Powder River Basin drilling accounted for 3.7 Bcfe. Capital spending in 2014 was primarily for evaluation drilling in the Piceance for Mancos Shale and development drilling in the Williston Bakken Shale play. Exploratory drilling investments were made to develop oil opportunities. Future capital spending rates are anticipated to be dependent on product prices and success in other future drilling.

In 2014, we had positive revisions of 8.5 Bcfe to previous reserve estimates. Most of the positive revision was the result of reporting natural gas liquids (NGL) in reserves (4.0 Bcfe) and higher equivalent prices of liquids and gas received at the wellhead (2.9 Bcfe). Natural gas in 2013 and prior years was reported wet. We changed our process in 2014 to separate NGL from the wet gas stream, which resulted in an estimated equivalent volume change of 4.0 Bcfe. Most of this change from increased NGL recovery is from the Powder River Finn Field and the Piceance wells. The industry standard multiplication of liquid production by 6 to arrive at the equivalent gas volume results in higher overall equivalent volumes. This is offset by negative revisions of dry natural gas resulting from higher shrink factors during processing of the wet gas to dry gas and NGLs. We will continue to report oil, natural gas and NGL volumes in the future.

Better wellhead performance resulted in an addition of 2.7 Bcfe, most of which was in the Powder River Basin Finn field and from our 2013 Piceance wells. Higher operating costs caused a minor negative revision of 0.1 Bcfe to 2014 year-end reserves. One proved-undeveloped location in the San Juan Basin was dropped (0.9 Bcfe) because of economics. We sold approximately 0.3 Bcfe of Williston Bakken properties in 2014.

SEC regulations require that proved undeveloped (PUD) locations meet the test of being developed within five years of being categorized as proved. In 2014, we had no PUD locations that were required to be dropped because of the five year rule.

Companies are required to include a narrative disclosure of the total quantity of PUD locations at year end, any material changes in PUD locations during the year and investment and progress made in converting the PUD locations to proved developed during the year.

- In 2013, we had 23 gross PUD locations for 4.7 Bcfe; all of the locations were in the Williston, Piceance and San Juan Basins. In 2014, seven locations in the Williston Bakken Shale were drilled and we invested $3.9 million and developed 0.6 Bcfe. One PUD in the San Juan Basin was dropped for economic reasons. Two PUD locations in the Williston Bakken were sold in 2014.

- Thirteen gross PUD locations remain undrilled as of December 31, 2014. The remaining 2013 PUD locations require approximately $10.5 million of future investment, and when drilled will develop approximately 3.2 Bcfe. Twelve locations are in the Williston Bakken and one location is in the Piceance Basin.

- In 2014, we added 21 gross PUD locations for future Williston Bakken, Piceance Mancos and Powder River Basin drilling.

- The number of locations and reconciliation of our proved undeveloped reserve and future development costs in our year-end proved undeveloped reserves as of December 31, 2014 were:

	Proved Reserves (in Bcfe)	Gross PUD Locations	Future Development Costs (in millions)
Existing 2013:			
Williston	1.8	21	$8.6
Piceance	2.3	1	$6.4
San Juan	0.6	1	$0.9
Year End Total 2013	4.7	23	$15.9
Dropped 2013:			
San Juan	(0.6)	(1)	$(0.9)
Drilled in 2014:			
Williston	(0.6)	(7)	$(3.9)
Sold:			
Williston	(0.3)	(2)	$(0.7)
Added in 2014:			
Williston	0.2	18	$1.0
Powder River	2.0	1	$13.0
Piceance	6.7	2	$17.5
	8.9	21	$31.5
Total Proved Undeveloped	12.1	34	$41.9

- None of our PUD locations have been reflected in our reserves for five or more years. Consistent with SEC guidance, these PUD locations will be monitored and reported each year until either drilled or revised.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31 (in thousands):

	2014	2013	2012
Unproved oil and gas properties	$75,329	$62,553	$59,526
Proved oil and gas properties	807,518	725,345	662,444
Gross capitalized costs	882,847	787,898	721,970
Accumulated depreciation, depletion and amortization and valuation allowances [a]	(612,012)	(592,505)	(575,913)
Net capitalized costs	$270,835	$195,393	$146,057

(a) Reflects the sale of the majority of the Williston Basin assets during 2012 recorded under the full-cost method of accounting.

Results of Operations

Following is a summary of results of operations for producing activities for the years ended December 31 (in thousands):

	2014	2013	2012
Revenue	$55,114	$54,884	$79,072
Production costs	22,155	20,140	23,483
Gain on sale of assets	—	—	(75,854)
Depreciation, depletion and amortization and valuation provisions	23,288	16,717	28,613
Impairment of long-lived assets	—	—	49,571
Total costs	45,443	36,857	25,813
Results of operations from producing activities before tax	9,671	18,027	53,259
Income tax benefit (expense)	(3,415)	(6,308)	(18,901)
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$6,256	$11,719	$34,358

Unproved Properties

Unproved properties not subject to amortization at December 31, 2014, 2013 and 2012 consisted mainly of exploration cost on various existing work-in-progress projects as well as leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $1.0 million, $1.1 million and $0.7 million of interest during 2014, 2013 and 2012, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined. We expect the exploration cost listed below to be added to the cost pool in the next year. The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2014 and notes the year in which the associated costs were incurred (in thousands):

	2014	2013	2012	Prior	Total
Leasehold acquisition cost	$16,077	$4,889	$35,823	$13,412	$70,201
Exploration cost	23,954	10,212	—	—	34,166
Capitalized interest	207	748	360	3,813	5,128

Total	$40,238	$15,849	$36,183	$17,225	$109,495

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure of discounted future net cash flows and changes relating to proved oil and gas reserves for the years ended December 31 (in thousands):

	2014	2013	2012
Future cash inflows	$675,973	$602,501	$502,769
Future production costs	(245,180)	(213,578)	(186,695)
Future development costs, including plugging and abandonment	(45,123)	(40,557)	(8,462)
Future income tax expense	(29,523)	(81,566)	(69,877)
Future net cash flows	356,147	266,800	237,735
10% annual discount for estimated timing of cash flows	(173,125)	(107,375)	(101,632)
Standardized measure of discounted future net cash flows	$183,022	$159,425	$136,103

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31 (in thousands):

	2014	2013	2012
Standardized measure - beginning of year	$159,425	$136,103	$203,357
Sales and transfers of oil and gas produced, net of production costs	(32,139)	(35,932)	(48,905)
Net changes in prices and production costs	(28,544)	15,126	(42,639)
Extensions, discoveries and improved recovery, less related costs	17,582	29,574	19,870
Changes in future development costs	3,195	(12,216)	43,854
Development costs incurred during the period	2,079	3,554	21,931
Revisions of previous quantity estimates	23,722	12,851	(86,277)
Accretion of discount	18,437	15,126	25,509
Net change in income taxes	19,265	(3,892)	36,578
Purchases of reserves	—	—	—
Sales of reserves [(a)]	—	(869)	(37,175)
Standardized measure - end of year	$183,022	$159,425	$136,103

(a) Reflects sale of Williston Basin assets in 2012.

Changes in the standardized measure from “revisions of previous quantity estimates” are driven by reserve revisions, modifications of production profiles and timing of future development. For all years presented, we had minimal net reserve revisions to prior estimates due to performance. Production forecast modifications are generally made at the well level each year through the reserve review process. These production profile modifications are based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments are reviewed each year and are often modified in response to current market conditions for items such as permitting and service availability.

(21) SALE OF OPERATING ASSETS AND DISCONTINUED OPERATIONS

Partial Sale of Electric Utilities Assets

On September 18, 2012, Colorado Electric completed the sale of an undivided 50% ownership interest in the Busch Ranch Wind project for $25 million. Colorado Electric retains the remaining undivided interest and is the operator of this jointly owned facility. Commercial operation of the newly constructed wind farm commenced on October 16, 2012. Colorado Electric will purchase our partner’s interest in the energy produced by the wind farm through a REPA. See Note 18 for further information.

Partial Sale of Oil and Gas Assets

On September 27, 2012, our Oil and Gas segment sold a majority of its Bakken and Three Forks shale assets in the Williston Basin in North Dakota. An effective date of July 1, 2012, was used to determine the sales price.

Our Oil and Gas segment follows the full-cost method of accounting for oil and gas activities. Typically, this methodology does not allow for gain or loss on sale and proceeds from sale are credited against the full cost pool. Gain or loss recognition is allowed when such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Williston Basin asset sale significantly altered the relationship and accordingly we recorded a gain of $76 million with the remainder of the proceeds recorded as a reduction in the full cost pool. As a result of the reduction in the full cost pool from the sale of these assets, the depreciation, depletion and amortization rate declined during 2013.

Net cash proceeds, subsequent to the true-up of all post-closing adjustments, were as follows (in thousands):

Cash proceeds received on date of sale	$243,314	
Adjusted for:		
Post close adjustments	2,793	
Transaction adviser fees	(1,400	)
Estimated payment for contractual obligation related to “back-in” fee *	(16,847	)
Net cash proceeds	$227,860	

* Required payment, triggered by the sale of the property, arising from a contractual obligation contained in the original participation agreement with the property operator.

Discontinued Operations

Results of operations for discontinued operations have been classified as Income from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income and Consolidated Statements of Cash Flows. For comparative purposes, all prior periods presented have been restated to reflect the reclassification on a consistent basis.

Energy Marketing Segment

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco Energy Inc. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds at date of sale were approximately $165 million, subject to final post-closing adjustments. Those proceeds represented $108 million received from the buyer and $58 million of cash retained from Enserco before closing.

The buyer asserted certain purchase price adjustments, some that we accepted, and several that we disputed. The disputed claims were resolved through a binding arbitration decision dated January 17, 2014. We expensed $1.4 million in 2012, relative to purchase price adjustments we accepted through a partial settlement agreement with the buyer, and an additional $1.1 million in 2013 relative to the claims assigned to arbitration. Loss from discontinued operations was $0.9 million for the twelve months ended December 31, 2013. Results for 2013 include the settlement of unresolved purchase price adjustments.

Operating results of the Energy Marketing segment included in Income (loss) from discontinued operations, net of tax on the accompanying Consolidated Statements of Income were as follows (in thousands):

For the Years Ended December 31,	2013	2012
Revenue	$—	$(604)
Pre-tax income (loss) from discontinued operations	—	(6,061)
Pre-tax gain (loss) on sale	(1,391)	(4,184)
Income tax (expense) benefit	507	3,268
Income (loss) from discontinued operations, net of tax [(a)]	$(884)	$(6,977)

(a) 2012 includes transaction related costs, net of tax, of $2.5 million for the year ended December 31, 2012.

Total indirect corporate costs and inter-segment interest expenses previously allocated to Enserco were not reclassified to discontinued operations in accordance with GAAP and instead have been reclassified to our Corporate segment.

128

(22) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2014 and 2013, revised for the effects of the errors described in Note 1.

	First Quarter			Second Quarter		
	(in thousands, except per share amounts, dividends and common stock prices)					
	As Reported	Adjustments	Revised	As Reported	Adjustments	Revised
2014						
Revenue	$460,169	$—	$460,169	$283,237	$—	$283,237
Operating income	$89,598	$834	$90,432	$46,577	$835	$47,412
Income (loss) from continuing operations	$48,118	$527	$48,645	$19,820	$527	$20,347
Net income (loss) available for common stock	$48,118	$527	$48,645	$19,820	$527	$20,347
Income (loss) per share - Basic	$1.09	$0.01	$1.10	$0.45	$0.01	$0.46
Income (loss) per share - Diluted	$1.08	$0.01	$1.09	$0.44	$0.02	$0.46
Dividends paid per share	$0.390	$—	$0.390	$0.390	$—	$0.390
Common stock prices - High	$59.05	$—	$59.05	$61.41	$—	$61.41
Common stock prices - Low	$51.09	$—	$51.09	$55.23	$—	$55.23

	Third Quarter			Fourth Quarter		
	(in thousands, except per share amounts, dividends and common stock prices)					
	As Reported	Adjustments	Revised	As Reported	Adjustments	Revised
2014						
Revenue	$272,087	$—	$272,087	$378,077	$—	$378,077
Operating income	$54,404	$834	$55,238	$69,951	$835	$70,786
Income (loss) from continuing operations	$26,836	$527	$27,363	$34,007	$527	$34,534
Net income (loss) available for common stock	$26,836	$527	$27,363	$34,007	$527	$34,534
Income (loss) per share - Basic	$0.60	$0.01	$0.61	$0.77	$0.01	$0.78
Income (loss) per share - Diluted	$0.60	$0.01	$0.61	$0.76	$0.01	$0.77
Dividends paid per share	$0.390	$—	$0.390	$0.390	$—	$0.390
Common stock prices - High	$62.13	$—	$62.13	$57.17	$—	$57.17
Common stock prices - Low	$47.87	$—	$47.87	$47.11	$—	$47.11

	First Quarter			Second Quarter		
	(in thousands, except per share amounts, dividends and common stock prices)					
	As Reported	Adjustments	Revised	As Reported	Adjustments	Revised
2013						
Revenue	$380,671	$—	$380,671	$279,826	$—	$279,826
Operating income	$79,846	$973	$80,819	$49,037	$974	$50,011
Income (loss) from continuing operations [(a)] [(b)]	$43,197	$615	$43,812	$30,518	$615	$31,133
Income (loss) from discontinued operations	$—	$—	$—	$—	$—	$—
Net income (loss) available for common stock [(a)] [(b)]	$43,197	$615	$43,812	$30,518	$615	$31,133
Income (loss) per share for continuing operations - Basic	$0.98	$0.01	$0.99	$0.69	$0.01	$0.70
Income (loss) per share for discontinued operations - Basic	$—	$—	$—	$—	$—	$—
Income (loss) per share - Basic	$0.98	$0.01	$0.99	$0.69	$0.01	$0.70
Income (loss) per share for continuing operations - Diluted	$0.97	$0.02	$0.99	$0.69	$0.01	$0.70
Income (loss) per share for discontinued operations - Diluted	$—	$—	$—	$—	$—	$—
Income (loss) per share - Diluted	$0.97	$0.02	$0.99	$0.69	$0.01	$0.70
Dividends paid per share	$0.380	$—	$0.380	$0.380	$—	$0.380
Common stock prices - High	$44.32	$—	$44.32	$50.53	$—	$50.53
Common stock prices - Low	$36.89	$—	$36.89	$43.19	$—	$43.19

	Third Quarter			Fourth Quarter		
	(in thousands, except per share amounts, dividends and common stock prices)					
	As Reported	Adjustments	Revised	As Reported	Adjustments	Revised
2013						
Revenue	$259,907	$—	$259,907	$355,448	$—	$355,448
Operating income	$55,566	$973	$56,539	$71,103	$973	$72,076
Income (loss) from continuing operations (a) (b)	$23,124	$616	$23,740	$19,007	$615	$19,622
Income (loss) from discontinued operations	$—	$—	$—	$(884)	$—	$(884)
Net income (loss) available for common stock (a) (b)	$23,124	$616	$23,740	$18,123	$615	$18,738
Income (loss) per share for continuing operations - Basic	$0.52	$0.02	$0.54	$0.43	$0.02	$0.45
Income (loss) per share for discontinued operations - Basic	$—	$—	$—	$(0.02)	$—	$(0.02)
Income (loss) per share - Basic	$0.52	$0.02	$0.54	$0.41	$0.02	$0.43
Income (loss) per share for continuing operations - Diluted	$0.52	$0.01	$0.53	$0.43	$0.01	$0.44
Income (loss) per share for discontinued operations - Diluted	$—	$—	$—	$(0.02)	$—	$(0.02)
Income (loss) per share - Diluted	$0.52	$0.01	$0.53	$0.41	$0.01	$0.42
Dividends paid per share	$0.380	$—	$0.380	$0.380	$—	$0.380
Common stock prices - High	$55.09	$—	$55.09	$54.89	$—	$54.89
Common stock prices - Low	$46.62	$—	$46.62	$47.00	$—	$47.00

(a) Includes unrealized mark-to-market gain (loss) for interest rate swaps of $4.8 million, $12 million, $2.0 million and $0.5 million after-tax in the first, second, third and fourth quarters, respectively.

(b) Fourth quarter 2013 includes $7.6 million after-tax for a make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt and a $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming’s project financing and write-off of deferred financing costs.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2014.

At the time the Original Filing was filed on February 25, 2015, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that disclosure controls and procedures were effective as of December 31, 2014.

Subsequent to the evaluation, management has determined that a deficiency in internal control existed related to the full-cost ceiling test impairment calculation, more fully discussed in Management's Report on Internal Control Over Financial Reporting (Revised), included in Item 8, represented a material weakness in our internal control over financial reporting. As a result, management has concluded our disclosure controls and procedures were not effective as of December 31, 2014.

In light of the material weakness referred to above, we performed additional procedures in order to conclude our consolidated financial statements in this Form 10-K/A were prepared in accordance with generally accepted accounting principles and as a result, our management, including our Chief Executive Officer and Chief Financial Officer, have concluded that the consolidated financial statements in this Form 10-K/A fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in conformity with accounting principles generally accepted in the United States.

Changes in Internal Controls over Financial Reporting

During the quarter ended December 31, 2014, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

While no changes to our internal controls over financial reporting are noted during the quarter ended December 31, 2014, a material weakness was identified as set forth in "Management's Report on Internal Control over Financial Reporting" (Revised), included in Item 8. Management believes the measures described below will remediate the identified control deficiency and enhance our internal controls over financial reporting.

In response to the identified material weakness, management reviewed the process and controls surrounding the oil and gas ceiling test impairment calculation. Management, with oversight from our Audit Committee, developed a plan of remediation that includes changes to processes to prevent or detect similar future occurrences. As a result of this plan, the following control remediation steps are being taken.

- Employees involved with preparation and review of the ceiling test calculation will be trained to reinforce the understanding of the requirements associated with appropriately performing this calculation, particularly as it relates to deferred taxes.
- The model used to calculate the ceiling test will be further updated and refined to ensure the appropriate application of accounting for all components is embedded within the model.
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Management will engage an external consultant with experience in the Oil and Gas industry to assist in reviewing the ceiling test model, when appropriate in consideration of risk associated with market or business changes.

ITEM 9B. OTHER INFORMATION

None.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2014, 2013 and 2012

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

3. Exhibits

SCHEDULE II
BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

Description	Balance at Beginning of Year	Adjustments	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
	(in thousands)					
Allowance for doubtful accounts:						
2014	$1,237	$—	$4,470	$4,233	$(8,424)	$1,516
2013	$768	$—	$2,780	$4,999	$(7,310)	$1,237
2012	$1,661	$—	$1,913	$3,822	$(6,628)	$768

3. Exhibits

Exhibit Number	Description
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed

	as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008). First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).

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10.6*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2008). Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013).
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10.10*†	Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2015. (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2014)
10.11*†	Form of Short-term Incentive for Omnibus Plan effective for awards granted on or after January 1, 2010 (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010).
10.12*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.13*†	Change in Control Agreement dated November 15, 2013 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 19, 2013).
10.14*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on November 19, 2013).
10.15*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008). First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010). Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012).

10.16*†	Third Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2015. (filed as Exhibit 10.16 to Registrant's Form 10-K for 2014).
10.17*†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.19 to the Registrant’s Form 10-K for 2011).
10.18*	Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on July 2, 2014).

10.19*	Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014).
10.20*	Credit Agreement, dated June 21, 2013 among Black Hills Corporation, as Borrower, J.P. Morgan Chase Bank, N.A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on June 24, 2013).
10.21*	Credit Agreement, dated May 29, 2014, among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 30, 2014).
10.22*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10 K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10 K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10 K for 1989).
10.23*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21*	List of Subsidiaries of Black Hills Corporation (filed as Exhibit 21 to Registrant's Form 10-K for 2014).
23.1	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Petroleum Engineer and Geologist (filed as Exhibit 23.2 to Registrant's Form 10-K for 2014).
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95*	

	Mine Safety and Health Administration Safety Data (Filed as Exhibit 95 to Registrant's Form 10-K for 2014).
99*	Report of Cawley, Gillespie & Associates, Inc. (filed as exhibit 99 to Registrant's Form 10-K for 2014).
101	Financial Statements in XBRL Format

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* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.
(a) See (a) 3. Exhibits above.
(b) See (a) 2. Schedules above.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By: /S/ DAVID R. EMERY
David R. Emery, Chairman, President
and Chief Executive Officer

Dated: August 6, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ DAVID R. EMERY David R. Emery, Chairman, President and Chief Executive Officer	Director and Principal Executive Officer	August 6, 2015
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	August 6, 2015

INDEX TO EXHIBITS

Exhibit Number	Description
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to the Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrants' Form 8-K filed on November 18, 2013).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed

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