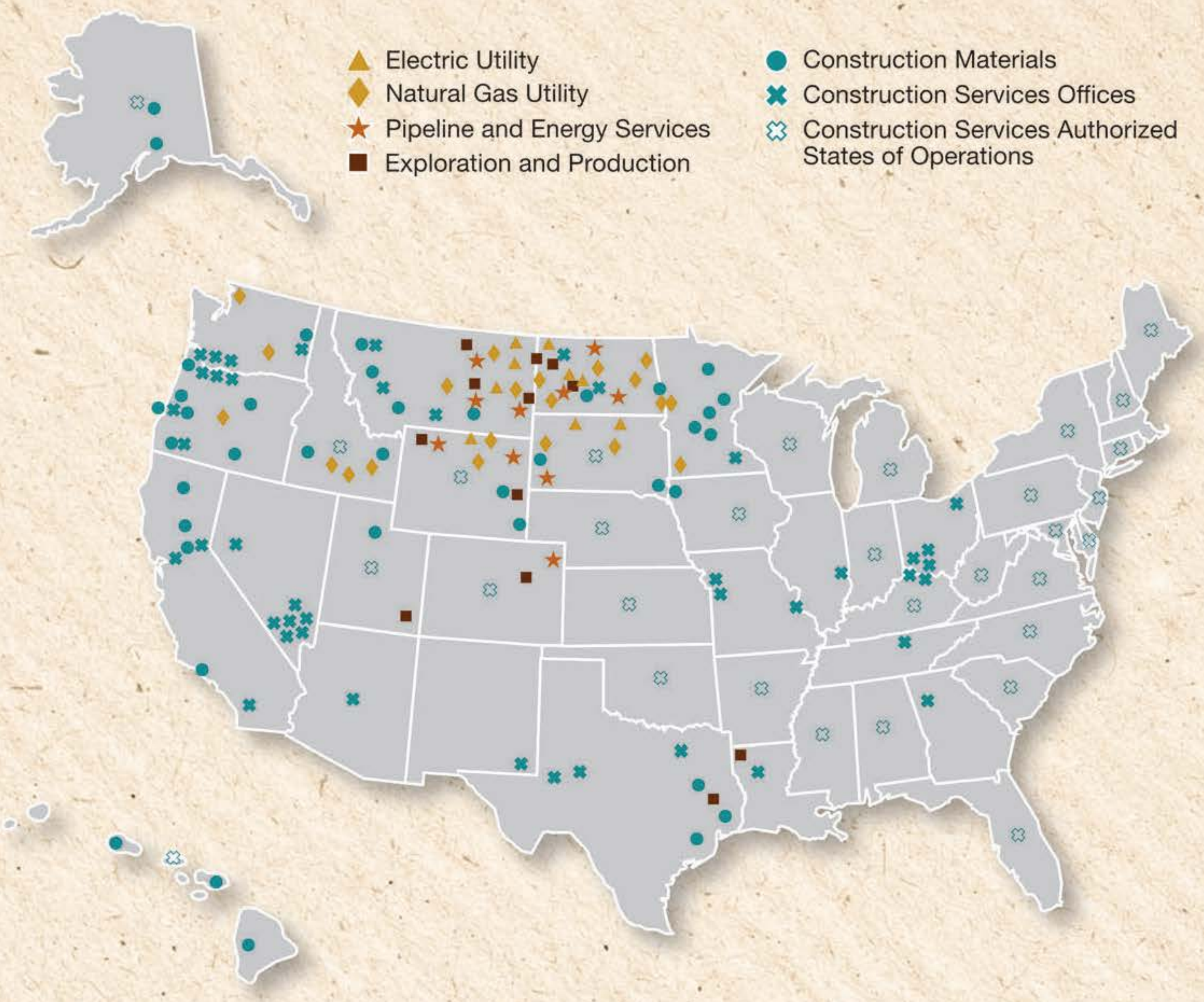
MDU RESOURCES GROUP, INC.

Building a Strong America®

2014 Annual Report
Form 10-K
Proxy Statement


MDU Resources Group, Inc.



Building a Strong America®

We are a member of the S&P MidCap 400 index. We provide value-added natural resource products and related services that are essential to energy and transportation infrastructure, including regulated utilities and pipelines, construction materials and services, and exploration and production.

MDU LISTED NYSE

Highlights

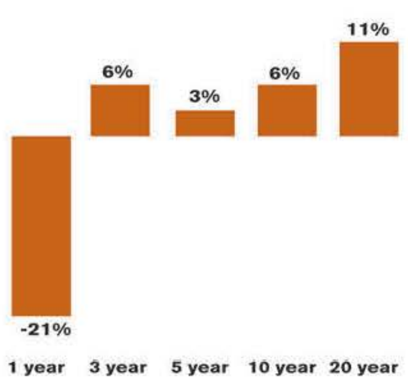
Years Ended December 31,	2014	2013
	(In millions, where applicable)	
Operating revenues	**$4,670.6**	$4,462.4
Operating income	**$ 488.2**	$ 492.9
Earnings on common stock	**$ 297.5**	$ 278.2
Adjustments net of tax:		
Exploration and production earnings	**(96.8)**	(94.5)
Discontinued operations	**(3.1)**	.3
Multiemployer pension plan withdrawal liability	**8.4**	–
Natural gas gathering asset impairment	**–**	9.0
Net benefit related to natural gas gathering operations litigation	**–**	(1.5)
Adjusted earnings	**$ 206.0**	$ 191.5
Earnings per share	**$ 1.55**	$ 1.47
Adjusted earnings per share	**$ 1.07**	$ 1.01
Dividends declared per common share	**$ .7150**	$ .6950
Weighted average common shares outstanding – diluted	**192.6**	189.7
Total assets	**$7,810.0**	$7,061.3
Total equity	**$3,249.8**	$2,855.9
Total debt	**$2,094.7**	$1,866.1
Capitalization ratios:		
Total equity	**60.8%**	60.5%
Total debt	**39.2**	39.5
	100%	100%
Price/earnings ratio (12 months ended)	**15.2x**	20.8x
Book value per common share	**$ 16.66**	$ 15.01
Market value as a percent of book value	**141.1%**	203.5%
Employees	**8,451**	9,133

Note: The company, in addition to presenting its earnings information in conformity with Generally Accepted Accounting Principles, has provided non-GAAP earnings data that reflect adjustments, all after taxes, to exclude: exploration and production earnings of $96.8 million in 2014 and $94.5 million in 2013, a multiemployer pension plan withdrawal liability of $8.4 million in 2014, a natural gas gathering asset impairment of $9.0 million in 2013 and a net benefit related to natural gas gathering operations litigation of $1.5 million in 2013. The company believes these non-GAAP financial measures are useful to investors because the items excluded are not indicative of the company's continuing operating results. Also, the company's management uses these non-GAAP financial measures as indicators for planning and forecasting future periods. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

Forward-looking statements: This Annual Report contains forward-looking statements within the meaning of section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in Part I, Forward-Looking Statements and Item 1A — Risk Factors of the company's 2014 Form 10-K. 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.

Total Shareholder Returns

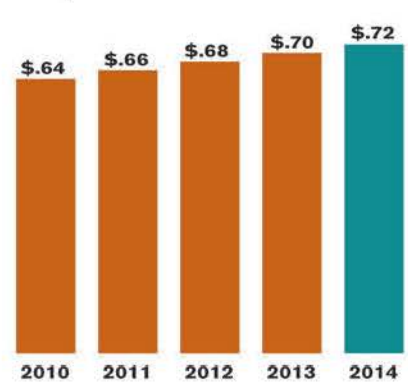
(as of December 31, 2014)



Dividends

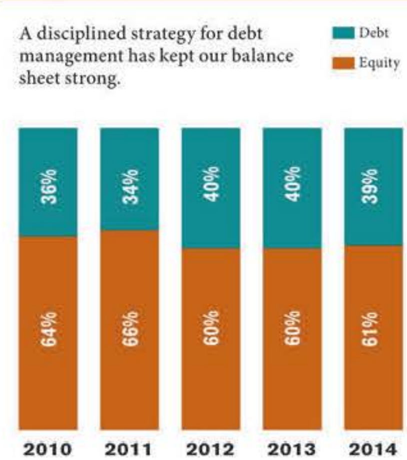
(per common share)

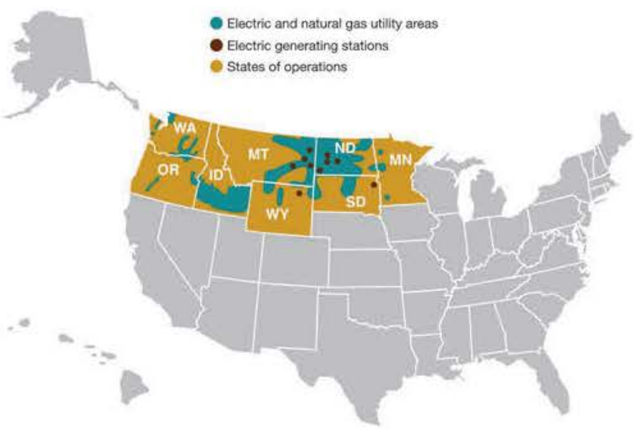
We have paid dividends uninterrupted for 77 years.



Capitalization Ratios

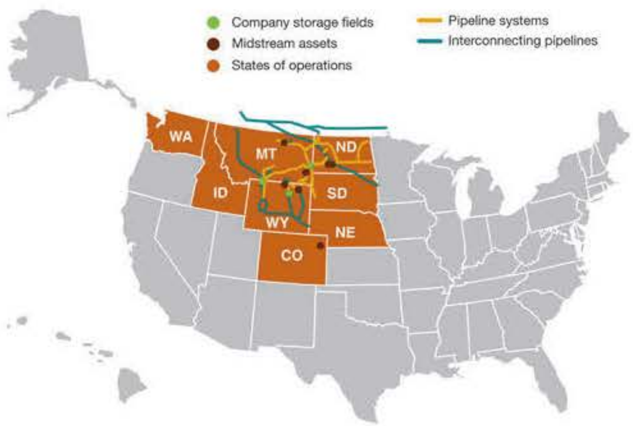
A disciplined strategy for debt management has kept our balance sheet strong.





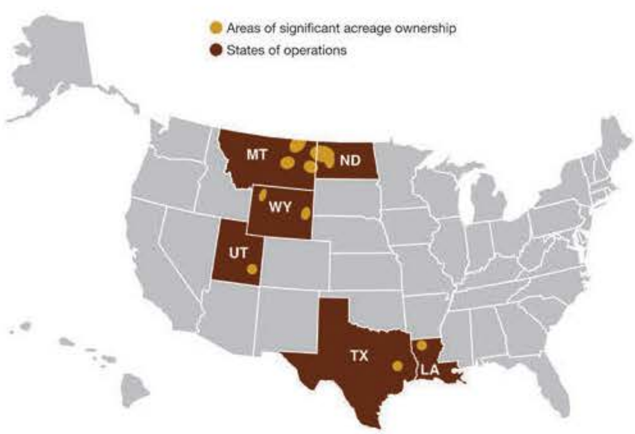
Electric and Natural Gas Utilities

MDU Resources Group's utility companies serve more than 1 million customers. Cascade Natural Gas Corporation distributes natural gas in Oregon and Washington. Great Plains Natural Gas Co. distributes natural gas in western Minnesota and southeastern North Dakota. Intermountain Gas Company distributes natural gas in southern Idaho. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. These operations also supply related value-added services.



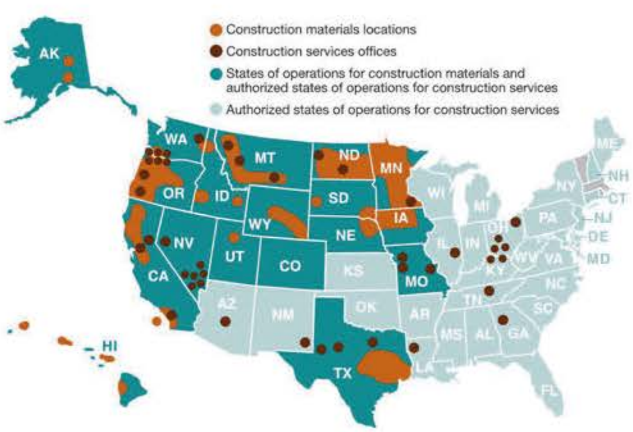
Pipeline and Energy Services

The pipeline and energy services segment provides natural gas transportation, underground storage, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment is constructing the Dakota Prairie Refining facility to refine Bakken crude oil. It also provides cathodic protection and other energy-related services.



Exploration and Production

Fidelity Exploration & Production Company is engaged in oil and natural gas development and production activities in the Rocky Mountain, Mid-Continent and Gulf States regions of the United States.



Construction Materials and Services

MDU Resources Group has a number of construction businesses.

- Knife River Corporation mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mix concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services.
- The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

- Heskett III, an 88-megawatt simple-cycle natural gas turbine at Mandan, North Dakota, was completed in August.
- The North Dakota Public Service Commission approved recovery of costs for the air quality control system at Big Stone Station.
- The company experienced 3 percent electric customer growth and 2 percent natural gas customer growth.
- The company filed applications for natural gas rate increases in Montana and Wyoming.

Revenues (millions)	
Electric	$277.9
Natural gas	$922.0
Earnings (millions)	
Electric	$36.7
Natural gas	$30.5
Electric retail sales (million kWh)	3,308.4
Natural gas distribution (MMdk)	
Sales	104.3
Transportation	145.9

- The utility group anticipates a record five-year capital program, including investments in new electric generation, transmission and distribution to serve growing customer demand.
- Montana-Dakota Utilities agreed to purchase a 107.5-megawatt wind farm that will be built in 2015 in North Dakota, and plans to construct 19 megawatts of natural gas-fired generation near Lewis & Clark Station in Sidney, Montana.
- Montana-Dakota Utilities is working with a partner on a 345-kilovolt transmission line for the Midcontinent Independent System Operator. The project is expected to be completed in 2019.

- Adjusted earnings improved 50 percent over 2013.
- Dakota Prairie Refining, the first greenfield diesel refinery built in the U.S. in more than 30 years, saw significant construction progress. The refinery is expected to operate in the second quarter of 2015.
- The Federal Energy Regulatory Commission approved a settlement of WBI Energy Transmission's requested rate increase.
- A number of natural gas pipeline projects were completed, including a pipeline serving a natural gas processing plant in western North Dakota, expansions in the Black Hills in South Dakota and in western North Dakota, and a 24-mile pipeline and processing facilities in Utah.

Revenues (millions)	$215.9
Earnings (millions)	$22.6
Pipeline (MMdk)	
Transportation	233.5
Gathering	38.4

- WBI Energy plans a record $1.1 billion capital program over the next five years.
- Pre-construction work continues on the Wind Ridge Pipeline, a 95-mile pipeline that is expected to be in service in 2017 to move 90 million cubic feet of natural gas per day to an announced fertilizer plant near Spiritwood, North Dakota.
- An agreement has been signed to construct a pipeline to connect the announced Demicks Lake gas processing plant in northwestern North Dakota to a new interconnection point with Northern Border Pipeline.
- WBI Energy is exploring the possibility of constructing a second diesel refinery.

- Closed in March on an acquisition of 24,500 net acres of leaseholds in the Powder River Basin in Converse County, Wyoming.
- Sold for approximately $200 million 4,363 net acres of oil and natural gas production assets in Mountrail County, North Dakota, effective May 1.
- Divested assets in South Texas.
- Produced, on average, more than 13,400 barrels of oil per day.

Revenues (millions)	$547.6
Earnings (millions)	$96.8
Production	
Oil (MBbls)	4,919
Natural gas liquids (MBbls)	609
Natural gas (MMcf)	20,822
Proved reserves	
Oil (MBbls)	43,918
Natural gas liquids (MBbls)	7,187
Natural gas (MMcf)	245,011

- MDU Resources Group plans to market Fidelity Exploration & Production for sale but has delayed the start of that process because of oil price volatility.
- In the current oil and natural gas price environment, Fidelity Exploration & Production is focusing on reducing its cost structure and creating value within existing assets.

- Knife River Corporation is the fifth-largest sand and gravel producer in the U.S.
- Wagner-Smith Equipment in November acquired the assets of Henderson Utility Equipment in Phoenix and broke ground on a new facility in Burleson, Texas.
- Capital Electric Line Builders completed ahead of schedule the biggest transmission line construction project in MDU Construction Services Group's history.
- MDU Construction Services Group ranks No. 10, based on annual revenues, on Engineering News Record's list of 600 U.S. specialty contractors.
- Knife River Corporation completed on time and on budget the largest highway contract in its history.

Revenues (millions)	
Construction materials	$1,765.3
Construction services	$1,119.5
Earnings (millions)	
Construction materials*	$59.9
Construction services	$54.5
Construction materials sales (millions)	
Aggregates (tons)	25,827
Asphalt (tons)	6,070
Ready-mix concrete (cubic yards)	3,460
Construction materials aggregate reserves (billion tons)	1.1

*Excludes an $8.4 million after-tax multiemployer pension plan withdrawal liability.

- Focusing on growth through organic opportunities as well as resuming acquisition activity.
- Combined construction backlog of $743 million entering 2015.
- Strategically managing 1.1 billion tons of aggregate reserves.

Notes:
- The earnings noted on this page exclude the Other category and intercompany eliminations. For GAAP earnings and for a discussion of adjustments to GAAP earnings, see page 1.
- Consolidated revenues reflect intersegment eliminations of $187.0 million.
- The Other category includes revenues of $9.4 million and earnings of $10.6 million.

Report to Stockholders

Our businesses performed well this past year, providing earnings at a level that sustained our post-recession recovery of 2013.

Our 2014 consolidated GAAP earnings were $297.5 million, or $1.55 per share, compared to $278.2 million, or $1.47 per share in 2013.

Because we have announced plans to exit the exploration and production business, we have provided consolidated adjusted earnings that exclude the results of that business, Fidelity Exploration & Production Company. Consolidated adjusted earnings totaled $206.0 million, or $1.07 per share, compared to $191.5 million, or $1.01 per share in 2013.

We appreciate the importance our shareholders place on the dividend, and we are proud of our record of paying a dividend uninterrupted for 77 years. In November, our Board of Directors increased the common stock dividend for the 24th consecutive year. This achievement is equaled by only about 100 of the 3,300 North American-listed, dividend-paying common stocks traded on a major exchange.

We believe that the operational success our businesses had in 2014, and their progress with "line-of-sight" projects that have advanced beyond the conceptual stage, make a compelling case for sustainable long-term growth. We plan to provide about $3.9 billion in capital investments over the next five years to develop these growth opportunities.

We are proud to share the 2014 achievements and growth strategies of our operating companies.

Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

Construction Businesses Deliver Strong Results

Our construction businesses' combined adjusted earnings increased 11 percent over 2013 to their highest level since 2007. It is the fourth consecutive year of stronger combined year-over-year earnings.

The construction services business had record earnings for the second consecutive year, and ranks No. 10 on Engineering News Record's list of 600 U.S. specialty contractors. Its outside electrical segment completed ahead of schedule the largest transmission line construction project in its history. It is a 345-kilovolt, double-circuit line stretching 108 miles from Wichita to Medicine Lodge, Kansas, and on to an interconnection at the Oklahoma border. At year-end, the construction services business had a work backlog of $305 million.

The construction materials and contracting business turned in the best second half of the year in its history. This business is the fifth-largest sand and gravel producer in the U.S. It also completed the largest contract in its history, a $55 million highway bypass that relieved serious Bakken oilfield traffic bottlenecks in Watford City, North Dakota. At year-end, the business had a work backlog of $438 million.

We expect to build on our construction businesses' industry leadership positions by moving them back into the growth mode that they enjoyed before the 2008 recession. Between 1992 and 2008 our construction businesses acquired almost 130 companies. They will use 2015 to identify potential acquisition candidates, along with organic growth opportunities. We anticipate providing a sizable merger and acquisition budget in 2016 to put their plans in motion.

Utility Continues Growth

Our utility business, which serves more than 1 million customers across eight states, once again experienced customer growth of about 2 percent. The business has a five-year capital program of $1.8 billion to build generation, transmission and electric and natural gas distribution facilities that will allow it to keep pace with the energy demands of its growing customer base. The capital budget is expected to grow the utility's rate base approximately 11 percent annually over the next five years on a compound basis.

About $478 million of capital expenditures are planned for this year, with $60 million concentrated in the Bakken oilfields, where electricity and natural gas customer growth has been particularly robust. While we may expect to see a tempering of activity with recent commodity pricing, we have a backlog of projects there to complete during the coming year.

In 2014 the business unit completed construction and placed into commercial operation a $77 million 88-megawatt natural gas turbine in North Dakota. It also signed an agreement to purchase a $200 million 107.5-megawatt Thunder Spirit Wind project that is expected to be completed by December 2015. With the addition of that project's 43 wind turbines, renewable energy will make up about 20 percent of the utility's generating portfolio.

This year the utility expects to complete an environmental upgrade to the Big Stone generating plant; its share of the cost is about $90 million. The utility, along with a partner, has received necessary route permits for a 160-mile 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota. It is a multivalue project for the Midcontinent Independent System Operator that is expected to be completed in 2019. The company's share of the cost is approximately $170 million.

The natural gas utility segment has a number of pipeline projects underway that would enhance the reliability and deliverability of its system in the Pacific Northwest and Idaho. It also is involved in a 30-mile natural gas line project that would serve the Hanford Nuclear Site in Washington, with an investment of approximately $60 million. In addition, the utility in 2014 made an initial investment in liquefied natural gas (LNG) production. This project capitalizes on the large amount of natural gas being produced in the Bakken, and offers opportunities for additional LNG projects.

Earnings Up 50 Percent at Pipeline, Energy Services

Our pipeline and energy services business increased earnings by 50 percent last year due to continued strong results from its 50 percent ownership interest in the Pronghorn natural gas and oil gathering and processing facility, and the first rate increase in 15 years on its interstate pipeline. Total transportation volumes reached a record level.

The business continued expanding its natural gas pipeline business with completion of a 15.5-mile pipeline that can transport up to 200 million cubic feet per day of natural gas from a Bakken processing plant to an interstate pipeline. It is the third such project completed in the last four years. It also is expanding its transmission system to increase capacity in the Black Hills in South Dakota.

We expect the Dakota Prairie Refining diesel refinery to begin commercial operation in the second quarter of this year. The project, which we are building in partnership with Calumet Specialty Products Partners, is the first greenfield refinery built in the U.S. since 1976. It will be able to process 20,000 barrels of Bakken crude oil per day into diesel fuel to help fill North Dakota's greatly undersupplied market.

We are disappointed that the construction schedule and costs have not met our original estimates. Winter weather and late revisions to the facility's electrical systems and controls have delayed the anticipated year-end 2014 startup and the total cost now is more than $400 million. However, we expect this will still be a profitable facility, with annualized EBITDA of $60 million to $80 million that will be shared equally with our partner. The company announced last year that it is evaluating the feasibility of a second refinery in the northern part of North Dakota. We expect that evaluation will continue through much of this year.

The pipeline and energy services business has a record five-year capital budget of $1.1 billion. It continues permitting and acquiring easements for the Wind Ridge Pipeline project, a 95-mile natural gas pipeline that would deliver approximately 90 million cubic feet per day to an announced fertilizer plant near Spiritwood, North Dakota. The project will cost approximately $120 million and is projected to be in service in 2017. There is an opportunity to expand the pipeline's capacity to serve other customers in eastern North Dakota.

The company also has entered into an agreement to build a pipeline connecting the Demicks Lake natural gas processing plant, which a third party has announced it will build in northwestern North Dakota, with the Northern Border Pipeline. The cost is estimated at $50 million to $60 million. The company will hold an open season to gauge additional interest in the project.

Oil Price Volatility Delays Exit From Exploration and Production Business

Last year we announced that we intend to market Fidelity Exploration & Production Company. In light of the recent volatility of oil prices we have delayed that process. While we can't predict an actual sale date, for forecasting purposes we are assuming a sale after 2015. Fidelity is a good business with good assets, but the amount of capital required to develop them and grow production at a meaningful level would significantly limit the amount of capital available to grow our other businesses.

The decision reflects a continuing evolution of our company, and results from a regular review by MDU Resources' Board of Directors and management of our strategies and portfolio of businesses to determine if there are opportunities to improve shareholder value. Over the years that has led to a number of changes in our company. For example, we consolidated a number of separate operations to build an interstate pipeline business, which we are now expanding into a broader midstream business. We exited the coal mining business and used that expertise to build an aggregates business that is among the 10 largest producers in the U.S. We built up an independent power business, then sold it to acquire a utility, expanding our regulated businesses.

We will continue to focus on maximizing the value of Fidelity until it is sold. We will work on lowering its cost structure, and minimize our investments in the first half of the year to allow service costs to better align with the lower commodity price environment. We anticipate some drilling in the second half of the year, but plan to limit spending to the operating cash flow that is generated by the business.

The delayed marketing will not affect our total five-year capital budget, but we expect to shift some funding into 2016. Among the work affected will be capital expenditures associated with a potential second refinery and acquisition capital at the construction businesses. The 2015 capital budget will be $692 million.

We continue to believe that exiting the exploration and production business is the right decision. As the growth opportunities discussed here illustrate, we believe we can create greater long-term value for our shareholders by focusing on our utility, construction and pipeline and energy services businesses — and at less risk, as the current decline in oil prices indicates.

The current oil price environment has led to much speculation about the future viability of shale oil development in the Bakken and other parts of the U.S. You probably have read about the slowdown in drilling rig activity and workforce reductions at oilfield service companies. The outcome is particularly important to MDU Resources, because every one of our businesses has had a profitable presence in the Bakken, and it is an important part of our growth.

While a prolonged period of lower commodity prices could slow future growth, electric utility customer growth in the Bakken last year was 5 percent, and natural gas customers increased by 3 percent. Our view is that this is not an end to the oil boom by any stretch of the imagination, but rather a temporary lull that might actually bring some benefits to North Dakota. It will provide a much-needed breather to catch up on infrastructure in communities where growth has outpaced resources. The current cost structure also is likely to drive industry innovations in technology and efficiency.

Thank You to Employees

The credit for our success in 2014 and what we expect to achieve in 2015 goes in large part to our outstanding employees, who number more than 11,300 during peak construction season. We want to thank them for their commitment to serving customers and shareholders with professionalism and integrity.

By their nature, our businesses demand a very high level of attention to safety, and our employees once again performed better than their industry peer averages. We want to recognize in particular the employees of our two construction businesses, Knife River and the Construction Services Group, who in 2014 had the best safety performances in their history.

Lastly, we want to thank you for investing in MDU Resources. We value the confidence your investment represents, and we are committed to growing this company in a manner that provides you with significant long-term value.

Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

February 20, 2015

Board of Directors

Harry J. Pearce
72 (18)
Detroit, Michigan

Chairman of MDU Resources Board of Directors

Retired, formerly chairman of Hughes Electronics Corp., a subsidiary of General Motors Corp., and former vice chairman and director of GM; a director of several organizations

Expertise: Multinational business management, leadership, finance, engineering and law

David L. Goodin
53 (2)
Bismarck, North Dakota

President and chief executive officer of MDU Resources

Formerly president and chief executive officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Thomas Everist
65 (20)
Sioux Falls, South Dakota

President and chairman of The Everist Co., a construction materials company; a director of several corporations

Expertise: Business management, construction and sand, gravel and aggregate production

Karen B. Fagg
61 (10)
Billings, Montana

Retired, formerly vice president of DOWL HKM and formerly chairman, chief executive officer and majority owner of HKM Engineering Inc.; on the board of several organizations

Expertise: Engineering, construction and business management

Mark A. Hellerstein
62 (2)
Denver, Colorado

Retired, formerly chairman, president and chief executive officer of St. Mary Land & Exploration Co.; a former director of Transocean Inc.

Expertise: Oil and natural gas industry, business management, accounting and finance

A. Bart Holaday
72 (7)
Denver, Colorado, and Grand Forks, North Dakota

Retired, formerly managing director of Private Markets Group of UBS Asset Management; on the board of several organizations

Expertise: Oil and natural gas industry, business development, finance and law

Dennis W. Johnson
65 (14)
Dickinson, North Dakota

Chairman, president and chief executive officer of TMI Corp., an architectural woodwork manufacturer; president of the Dickinson City Commission; a former director of Federal Reserve Bank of Minneapolis

Expertise: Business management, engineering and finance

William E. McCracken
72 (2)
Warren, New Jersey

Retired, formerly chairman and chief executive officer of CA Technologies; previously held executive positions with IBM Corp.; a director of several organizations; a former director of IKON Office Solutions Inc.

Expertise: Multinational business management, corporate governance and technology

Patricia L. Moss
61 (12)
Bend, Oregon

Vice chairman of Cascade Bancorp and Bank of the Cascades, formerly president and chief executive officer of Cascade Bancorp and Bank of the Cascades; on the board of several organizations

Expertise: Finance, banking, business development and human resources

J. Kent Wells
58 (2)
Denver, Colorado

Vice chairman of the corporation and chief executive officer of Fidelity Exploration & Production Company

Formerly an executive with one of the world's largest oil and natural gas production companies

John K. Wilson
60 (12)
Omaha, Nebraska

Formerly president of Durham Resources LLC, a privately held financial management company, and formerly a director of a mutual fund; on the board of several organizations

Expertise: Public utilities, accounting and finance

Audit Committee
Dennis W. Johnson, Chairman
Mark A. Hellerstein
A. Bart Holaday
John K. Wilson

Compensation Committee
Thomas Everist, Chairman
Karen B. Fagg
William E. McCracken
Patricia L. Moss

Nominating and Governance Committee
Karen B. Fagg, Chairman
A. Bart Holaday
William E. McCracken
Patricia L. Moss

Board of Directors Changes
Thomas C. Knudson did not stand for re-election at the 2014 Annual Meeting held April 22, 2014.

J. Kent Wells announced his resignation from the Board of Directors, effective February 28, 2015.

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2014.

Corporate Management

David L. Goodin
53 (32)

President and Chief Executive Officer of MDU Resources

Serves on the company's Board of Directors and as chairman of the board of all major subsidiary companies; formerly president and chief executive officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

David C. Barney
59 (29)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River

Steven L. Bietz
56 (34)

President and Chief Executive Officer of WBI Holdings, Inc.

Formerly held executive and management positions with WBI Holdings

Mark A. Del Vecchio
55 (12)

Vice President of Human Resources of MDU Resources

Formerly director of compensation and executive programs of MDU Resources

Dennis L. Haider
62 (37)

Executive Vice President of Business Development of MDU Resources

Formerly executive vice president of marketing, gas supply and business development of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Nicole A. Kivisto
41 (20)

President and Chief Executive Officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Formerly vice president of operations of Great Plains Natural Gas and Montana-Dakota Utilities

Cynthia J. Norland
60 (31)

Vice President of Administration of MDU Resources

Formerly associate general counsel of MDU Resources

Paul K. Sandness
60 (35)

General Counsel and Secretary of MDU Resources

Serves as general counsel and secretary of all major subsidiary companies; formerly senior attorney of MDU Resources and held other positions of increasing responsibility

Doran N. Schwartz
45 (10)

Vice President and Chief Financial Officer of MDU Resources

Serves as the senior financial officer and member of the board of directors of all major subsidiary companies; formerly chief accounting officer of MDU Resources

Jeffrey S. Thiede
52 (11)

President and Chief Executive Officer of MDU Construction Services Group, Inc.

Formerly held executive and management positions with MDU Construction Services Group

J. Kent Wells
58 (4)

Vice Chairman of the Corporation and Chief Executive Officer of Fidelity Exploration & Production Company

Formerly an executive with one of the world's largest oil and natural gas production companies

Other Corporate and Senior Company Officers

William R. Connors, 53 (11)
Vice President of Renewable Resources of MDU Resources

Nathan W. Ring, 39 (14)
Vice President, Controller and Chief Accounting Officer of MDU Resources

Jason L. Vollmer, 37 (10)
Treasurer and Director of Cash and Risk Management of MDU Resources

Management Changes

Nathan W. Ring was named vice president, controller and chief accounting officer of MDU Resources, effective January 3, 2014.

Jason L. Vollmer was named treasurer and director of cash and risk management of MDU Resources, effective November 29, 2014.

Nicole A. Kivisto was named president and chief executive officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co., effective January 9, 2015.

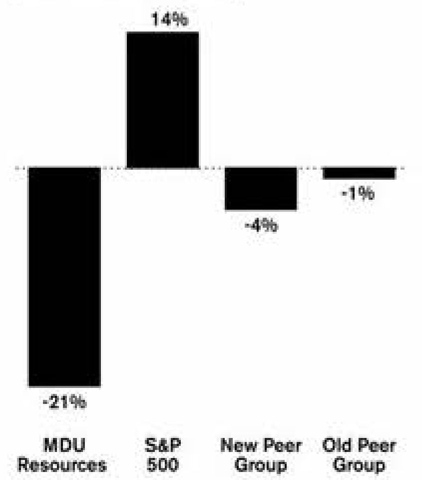
Patrick L. O'Bryan was named chief executive officer, in addition to his role as president, of Fidelity Exploration & Production Company, effective March 1, 2015. He replaces **J. Kent Wells,** who announced his retirement, effective February 28, 2015.

Numbers indicate age and years of service ( ) as of December 31, 2014.

Stockholder Return Comparison

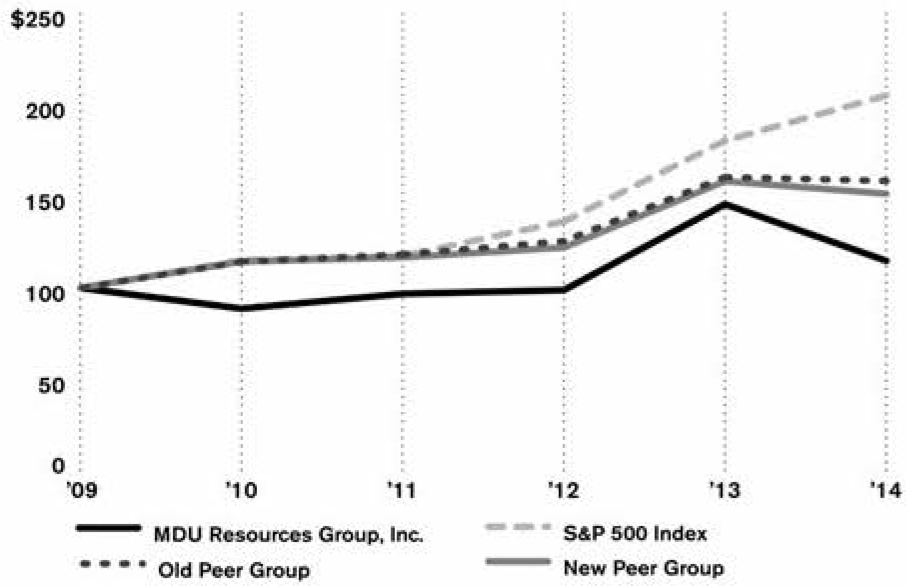
Comparison of One-Year Total Stockholder Return

(as of December 31, 2014)



Comparison of Five-Year Total Stockholder Return (in dollars)

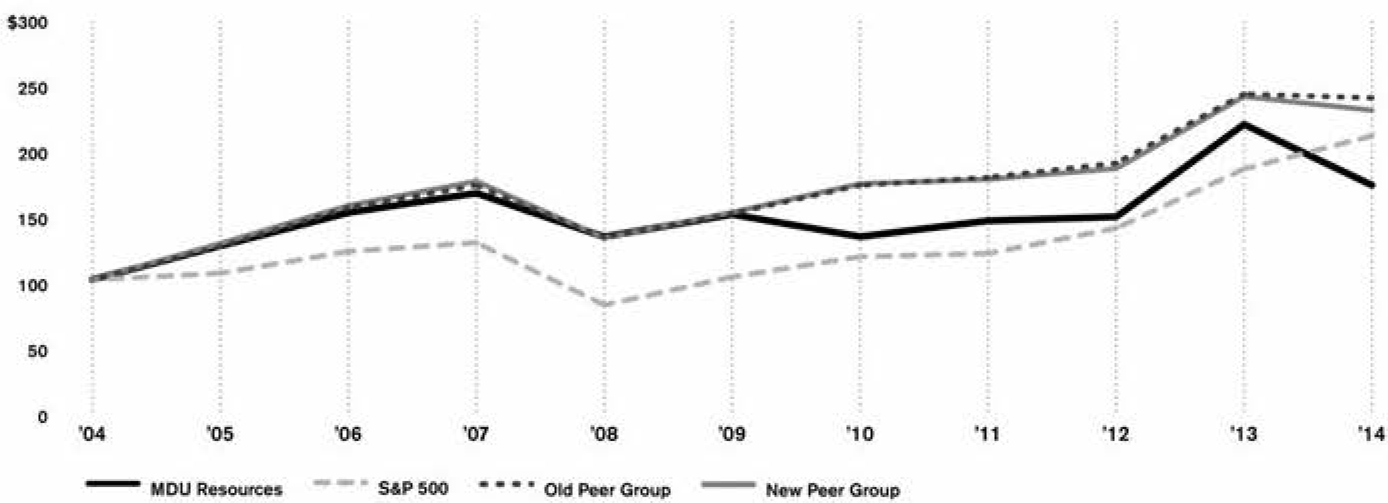
$100 invested December 31, 2009, in MDU Resources was worth $114.87 at year-end 2014.



	2009	2010	2011	2012	2013	2014
MDU Resources Group, Inc.	$100.00	$ 88.67	$ 96.77	$ 98.78	$145.74	$114.87
S&P 500 Index	100.00	115.06	117.49	136.30	180.44	205.14
New Peer Group	100.00	114.40	116.69	122.08	158.30	151.43
Old Peer Group	100.00	114.27	118.26	125.54	160.48	158.51

Comparison of 10-Year Total Stockholder Return (in dollars)

$100 invested December 31, 2004, in MDU Resources was worth $171.89 at year-end 2014.



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
MDU Resources Group, Inc.	$100.00	$125.69	$150.95	$165.82	$132.56	$149.64	$132.68	$144.82	$147.82	$218.10	$171.89
S&P 500 Index	100.00	104.91	121.48	128.16	80.74	102.11	117.49	119.97	139.17	184.25	209.47
New Peer Group	100.00	127.49	156.30	174.80	131.78	151.15	172.91	176.38	184.51	239.27	228.88
Old Peer Group	100.00	125.26	154.68	171.62	131.81	150.31	171.75	177.76	188.70	241.22	238.25

Stockholder Return Comparison

Data is indexed to December 31, 2013, for the one-year total stockholder return comparison, December 31, 2009, for the five-year total stockholder return comparison and December 31, 2004, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer groups. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group are weighted according to the issuer's stock market capitalization at the beginning of the period.

Beginning in 2014, a new peer group was established. Changes were made to replace two utility and pipeline peers with peers that operate in the company's same geographic area, and replace an exploration and production peer that was removed due to a merger. The changes better reflect the nature of the company's business. The graphs show stockholder return performance for both the old and new peer groups.

New peer group issuers are ALLETE, Inc., Alliant Energy Corp., Atmos Energy Corp., Avista Corp., Bill Barrett Corp., Black Hills Corp., Comstock Resources Inc., EMCOR Group Inc., EQT Corp., Granite Construction Inc., Martin Marietta Materials Inc., National Fuel Gas Co., Northwest Natural Gas Co., Quanta Services Inc., Questar Corp., SM Energy Co., Sterling Construction Co. Inc., Swift Energy Co., Vectren Corp., Vulcan Materials Co. and Whiting Petroleum Corp.

Old peer group issuers are Alliant Energy Corp., Atmos Energy Corp., Black Hills Corp., Comstock Resources Inc., EMCOR Group Inc., EQT Corp., Granite Construction Inc., Martin Marietta Materials Inc., National Fuel Gas Co., Northwest Natural Gas Co., Quanta Services Inc., Questar Corp., SCANA Corp., SM Energy Co., Southwest Gas Corp., Sterling Construction Co. Inc., Swift Energy Co., Vectren Corp., Vulcan Materials Co. and Whiting Petroleum Corp.

During 2014, Pike Corp. and Texas Industries Inc. merged with other companies. As a result, the companies were removed from both peer groups for the entire period shown in the performance graphs.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

OR

☐ 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 1-3480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	41-0423660
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:

Preferred Stock, par value $100
(Title of Class)

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒.

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 ☒ No ☐.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐.

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 the 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. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Small reporting company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2014: $6,795,350,628.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 13, 2015: 194,420,095 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2015 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

The following abbreviations and acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BLM	Bureau of Land Management
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the first quarter of 2015, the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
California Superior Court	Superior Court of the State of California, County of Los Angeles (South District - Long Beach)
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Connolly-Pacific	Connolly-Pacific Co., an indirect wholly owned subsidiary of Knife River
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at December 31, 2014, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010, respectively, with the remaining 2.5 percent ownership interest sold in January 2015)
EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
ESA	Endangered Species Act

Definitions

Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
GVTC	Generation Verification Test Capacity
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
NGL	Natural gas liquids
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission

Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2015 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. 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 (many of which are based, in turn, upon further 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 - MD&A - Prospective Information.

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 this Form 10-K, including statements contained within Item 1A - Risk Factors.

Items 1 and 2. Business and Properties

General

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Cascade distributes natural gas in Oregon and Washington. Intermountain distributes natural gas in Idaho. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the exploration and production segments), Knife River (construction materials and contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

The Company's investment in ECTE is reflected in the Other category. For more information, see Item 8 - Note 4.

As of December 31, 2014, the Company had 8,451 employees with 163 employed at MDU Resources Group, Inc., 1,030 at Montana-Dakota, 34 at Great Plains, 313 at Cascade, 225 at Intermountain, 586 at WBI Holdings, 2,508 at Knife River and 3,592 at MDU Construction Services. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2014.

At Montana-Dakota and WBI Energy Transmission, 349 and 78 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2015, and March 31, 2018, for Montana-Dakota and WBI Energy Transmission, respectively.

At Cascade, 139 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2015.

At Intermountain, 117 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2016.

Knife River operates under 43 labor contracts that represent 460 of its construction materials employees. Knife River is in negotiations on 4 of its labor contracts.

MDU Construction Services has 134 labor contracts representing the majority of its employees.

The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 - MD&A and Item 8 - Note 15 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 - Note 19. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and the Bremerton Gasworks Superfund Site.

The Company produces GHG emissions primarily from its fossil fuel electric generating facilities, as well as from natural gas pipeline and storage systems, operations of equipment and fleet vehicles, and oil and natural gas exploration and development activities. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions. Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A - Risk Factors.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q and current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's Web site as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the SEC. The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.

Electric

General Montana-Dakota provides electric service at retail, serving more than 138,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2014. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 11 electric generating facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,100 and 5,000 miles of transmission and distribution lines, respectively, and 58 transmission and 279 distribution substations. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2014, Montana-Dakota's net electric plant investment was $960.8 million.

The percentage of Montana-Dakota's 2014 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 64 percent; Montana - 21 percent; Wyoming - 10 percent; and South Dakota - 5 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters.

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its integrated system. MISO is a regional transmission organization responsible for operational control of the transmission systems of its members. MISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of MISO, Montana-Dakota's generation is sold into the MISO energy market and its energy needs are purchased from that market.

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of western North Dakota, including Bismarck, Mandan, Dickinson, Williston and Watford City; eastern Montana, including Sidney, Glendive and Miles City; and northern South Dakota, including Mobridge. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 582,083 kW in January 2014. The maximum summer electric peak demand experienced to date was 573,587 kW in July 2012. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will occur during the summer and the sales growth rate through 2019 will approximate 6 percent annually. The interconnected system consists of ten electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 577,943 kW and total net ZRCs of 444.8 in 2014. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within MISO. For 2014, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 584.0. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within MISO was 522.4 ZRCs for 2014. Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station) is 327,758 kW. Three combustion turbine peaking stations, two wind electric generating facilities, a heat recovery electric generating facility and three small portable diesel generators supply the balance of Montana-Dakota's interconnected system electric generating capability.

Montana-Dakota has a contract for capacity of 120 MW for the period June 1, 2014 to May 31, 2015. On November 20, 2014, Montana-Dakota entered into an asset purchase agreement with Thunder Spirit Wind, LLC, to purchase for approximately $200 million a wind farm of 107.5 MW of installed capacity to be located in southwest North Dakota upon commercial operation subject to regulatory approval. Montana-Dakota has applied for an advance determination of prudence and a certificate of public convenience and necessity from the NDPSC for purchase of the wind farm. If Montana-Dakota does not receive regulatory approval for the purchase of the wind farm, it will purchase the output of the wind farm from Thunder Spirit Wind, LLC under a power purchase agreement. The project is expected to begin commercial operation in the fourth quarter of 2015. The generation will interconnect at Montana-Dakota's substation near Hettinger, North Dakota. Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2014, Montana-Dakota purchased approximately 29 percent of its net kWh needs for its interconnected system through the MISO market.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 61,501 kW in July 2012. Montana-Dakota has a power supply contract with Black Hills Power, Inc. to purchase up to 49,000 kW of capacity annually through December 31, 2016. Wygen III serves a portion of the needs of its Sheridan-area customers.

The following table sets forth details applicable to the Company's electric generating stations:

Generating Station	Type	Nameplate Rating (kW)	2014 ZRCs (a)	2014 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	93.2	682,333
Heskett	Steam	86,000	89.0	547,268
Heskett	Combustion Turbine	89,038	(c)	28,057
Glen Ullin	Heat Recovery	7,500	4.4	31,441
Cedar Hills	Wind	19,500	3.7	59,420
Diesel Units	Oil	5,475	4.6	40
South Dakota:				
Big Stone (b)	Steam	94,111	101.3	576,957
Montana:				
Lewis & Clark	Steam	44,000	52.0	290,193
Glendive	Combustion Turbine	75,522	72.1	1,911
Miles City	Combustion Turbine	23,150	19.9	365
Diamond Willow	Wind	30,000	4.6	96,534
		577,943	444.8	2,314,519
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	205,419
		605,943	444.8	2,519,938

(a) Interconnected system only. MISO requires generators to obtain their summer capability through the GVTC. The GVTC is then converted to ZRCs by applying each generator's forced outage factor against its GVTC. Wind generator's ZRCs are calculated based on a wind capacity study performed annually by MISO. ZRCs are used to meet supply obligations within MISO.
(b) Reflects Montana-Dakota's ownership interest.
(c) Pending accreditation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company under contracts that expire in May 2016, April 2016 and December 2017, respectively. The Coyote Station coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The Heskett and Lewis & Clark coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 450,000 to 550,000 tons and 250,000 to 350,000 tons per contract year, respectively.

Montana-Dakota has a contract with Coyote Creek for coal supply to the Coyote Station beginning May 2016 until December 2040. Montana-Dakota estimates the Coyote Station coal supply agreement to be approximately 2.5 million tons per contract year. For more information, see Item 8 - Note 19.

Montana-Dakota has coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 1.0 million tons in 2015 and 500,000 tons in 2016 from Peabody Coalsales, LLC at contracted pricing. The remainder of the Big Stone Station fuel requirements will be secured through separate future contracts.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., to supply the coal requirements of Wygen III at contracted pricing through June 1, 2060. Montana-Dakota estimates the maximum annual coal consumption of the facility to be 585,000 tons.

The average cost of coal purchased, including freight, at Montana-Dakota's electric generating stations (including the Big Stone, Coyote and Wygen III stations) was as follows:

Years ended December 31,	**2014**	2013	2012
Average cost of coal per MMBtu	**$ 1.74**	$ 1.73	$ 1.69
Average cost of coal per ton	**$ 25.11**	$ 25.32	$ 24.77

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through mid-2016. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources, or acquiring additional capacity through power purchase contracts or the MISO capacity auction. For more information regarding potential power generation projects, see Item 7 - MD&A - Prospective Information - Electric and natural gas distribution.

Montana-Dakota has major interconnections with its neighboring utilities and considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota reflects monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring those electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in purchased power costs (including demand charges but excluding increases or decreases from base coal price) related to power supply and Montana-Dakota is deferring costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 14 to 25 months from the time such costs are paid. For more information, see Item 8 - Note 6.

In North Dakota, Montana-Dakota recovers in rates the costs associated with environmental upgrades at Big Stone Station. Montana-Dakota will maintain a tracker account until all costs are recovered or until the associated costs are reflected in base rates as a part of a general rate case.

In North Dakota, Montana-Dakota has the ability to recover the costs associated with new generation through a rider mechanism. On January 9, 2015, Montana-Dakota implemented a generation resource recovery rider to recover the costs associated with the Heskett natural gas combustion turbine which was commissioned in August 2014. Montana-Dakota will utilize this rider mechanism for new generation until such time as the costs and investment are included in base rates. Montana-Dakota also has in place in North Dakota a transmission tracker to recover transmission costs from its regional transmission operator, MISO. The tracking mechanism has an annual true-up.

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. The Title V Operating Permit renewal application for Big Stone Station was submitted timely to the South Dakota Department of Environment and Natural Resources in November 2013. The Title V Operating Permit renewal application for Lewis & Clark Station was submitted timely in February 2014 to the Montana DEQ and the Title V Operating Permit renewal application for Heskett Station was submitted timely in August 2014 to the North Dakota Department of Health. The Montana DEQ issued a Montana Air Quality Permit in January 2015 to Montana-Dakota for the addition of two 9.3 MW engines and associated operating equipment at Lewis & Clark Station.

State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota incurred $28.3 million of environmental capital expenditures in 2014, largely for the installation of a BART air quality control system at the Big Stone Station. Capital expenditures are estimated to be $42 million, $7 million and $2 million in 2015, 2016 and 2017, respectively, to maintain environmental compliance as new emission controls are required, including the installation of a BART air quality control system, as discussed above. Projects for 2015 through 2017 also include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals control equipment installation at electric generating stations and anticipated costs for coal ash disposal. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by future air and wastewater effluent discharge regulation, as well as potential new GHG legislation or regulation. In particular, such GHG legislation or regulation would likely increase capital expenditures and operational costs associated with GHG emissions compliance until carbon capture technology becomes economical, at which time capital expenditures may be necessary to incorporate such technology into existing or new generating facilities. Montana-Dakota expects that it will recover the operational and capital expenditures for GHG regulatory compliance in its rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains, Cascade and Intermountain, which sell natural gas at retail, serving over 892,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2014, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,800 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2014, the natural gas distribution operations' net natural gas distribution plant investment was $1.2 billion.

The percentage of the natural gas distribution operations' 2014 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 29 percent; Washington - 25 percent; North Dakota - 16 percent; Montana - 9 percent; Oregon - 8 percent; South Dakota - 7 percent; Minnesota - 4 percent; and Wyoming - 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Mandan, Dickinson, Wahpeton, Williston, Watford City, Minot and Jamestown; central and eastern Oregon, including Bend, Pendleton, Ontario and Baker City; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Aberdeen, Wenatchee/Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan and Lovell. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a weather normalization mechanism discussed in Regulatory Matters. In addition to the residential and commercial sales, the utilities transport natural gas for larger commercial and industrial customers who purchase their own supply of natural gas.

Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. These services have enhanced the natural gas distribution operations' competitive posture with alternative fuels, although certain customers have bypassed the distribution systems by directly accessing transmission pipelines within close proximity. These bypasses did not have a material effect on results of operations.

The natural gas distribution operations and various distribution transportation customers obtain their system requirements directly from producers, processors and marketers. The Company's purchased natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements with WBI Energy Transmission, Northern Border Pipeline Company, Northwest Pipeline GP, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Westcoast Energy Inc., Ruby Pipeline LLC, Foothills Pipe Lines Ltd. and NOVA Gas Transmission Ltd. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including WBI Energy Transmission, Questar Pipeline Company, Northwest Pipeline GP and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs within a period ranging from 12 to 28 months.

Montana-Dakota's North Dakota and South Dakota natural gas tariffs contain weather normalization mechanisms applicable to firm customers that adjust the distribution delivery charge revenues to reflect weather fluctuations during the November 1 through May 1 billing periods.

On March 13, 2013, the OPUC approved an extension of Cascade's decoupling mechanism until December 31, 2015. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

For more information on regulatory matters, see Item 8 - Note 18.

Environmental Matters The natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The natural gas distribution operations believe they are in substantial compliance with those regulations.

The Company's natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Certain locations of the natural gas distribution operations routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required. Capital and operational expenditures for natural gas distribution operations could be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for energy efficiency and conservation programs and operational costs associated with GHG emissions compliance. Natural gas distribution operations expect to recover the operational and capital expenditures for GHG regulatory compliance in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

The natural gas distribution operations did not incur any material environmental expenditures in 2014. Except as to what may be ultimately determined with regard to the issues described later, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017.

Montana-Dakota has had an economic interest in four historic manufactured gas plants and Great Plains has had an economic interest in one historic manufactured gas plant within their service territories. Montana-Dakota is investigating a former manufactured gas plant in Montana and is planning investigation of a former manufactured gas plant in North Dakota. Montana-Dakota will seek recovery in its natural gas rates charged to customers for any remediation costs incurred for these sites. None of the remaining former manufactured gas plant sites of Montana-Dakota or Great Plains are being actively investigated. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved in the investigation and remediation of three manufactured gas plants in Washington and Oregon. See Item 8 - Note 19 for a further discussion of these three manufactured gas plants. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Pipeline and Energy Services

General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 3,800 miles of transmission, gathering and storage lines in Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, producers, natural gas marketers and others, and serve to enhance system deliverability. Its system is strategically located near five natural gas producing basins, making natural gas supplies available to its transportation and storage customers. The system has 13 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters, and at December 31, 2014, its net plant investment was $358.8 million.

The nonregulated business of this segment owns and operates gathering facilities in Colorado, Montana and Wyoming. It also owns a 50 percent undivided interest in the Pronghorn assets located in western North Dakota that were acquired in 2012, which include a natural gas processing plant, both oil and gas gathering pipelines, an oil storage terminal and an oil pipeline. In total, facilities include approximately 1,600 miles of operated field gathering lines, some of which interconnect with WBI Energy's regulated pipeline system. The nonregulated business provides natural gas and oil gathering services, natural gas processing and a variety of other energy-related services, including cathodic protection, water hauling, contract compression operations, measurement services, and energy efficiency product sales and installation services to large end-users.

WBI Energy, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and, when complete, it will process Bakken crude oil into diesel, which will be marketed within the Bakken region. Other by-products, naptha and atmospheric tower bottoms, are expected to be railed to other areas. Total project costs are estimated to be more than $400 million, with a projected in-service date in the second quarter of 2015.

This segment also includes an energy services business which provides natural gas purchase and sales services to local distribution companies, producers, other marketers and a limited number of large end-users, primarily using natural gas produced by Fidelity. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. At December 31, 2014, it has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 1.6 MMdk in 2015. The Company currently estimates that it can adequately meet the requirements of these contracts based upon the estimated natural gas production and reserves of Fidelity.

A majority of its pipeline and energy services business is transacted in the northern Great Plains and Rocky Mountain regions of the United States.

For information regarding natural gas gathering operations litigation, see Item 8 - Note 19.

System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region and from off-system supply sources. While certain traditional regional supply sources are in various stages of decline, incremental supply from nontraditional sources have been developed which has helped support WBI Energy Transmission's supply needs. This includes new natural gas supply associated with the continued development of the Bakken area in Montana and North Dakota. The Powder River Basin also provides a nontraditional natural gas supply to the WBI Energy Transmission system. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission expects to facilitate the movement of these supplies by making available its transportation and storage services. WBI Energy Transmission will continue to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.

WBI Energy Transmission's underground natural gas storage facilities have a certificated storage capacity of approximately 353 Bcf, including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. These storage facilities enable customers to purchase natural gas at more uniform daily volumes throughout the year and meet winter peak requirements.

WBI Energy Transmission competes with several pipelines for its customers' transportation, storage and gathering business and at times may discount rates in an effort to retain market share. However, the strategic location of its system near five natural gas producing basins and the availability of underground storage and gathering services, along with interconnections with other pipelines, serve to enhance its competitive position.

Although certain of WBI Energy Transmission's firm customers, including its largest firm customer Montana-Dakota, serve relatively secure residential and commercial end-users, they generally all have some price-sensitive end-users that could switch to alternate fuels.

WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for 2014 represented 46 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2017. In addition, Montana-Dakota has contracts with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2035.

The nonregulated business competes with several midstream companies for existing customers, for the expansion of its systems and for the installation of new systems. Its strong position in the fields in which it operates, its focus on customer service and the variety of services it offers, along with its interconnection with various other pipelines, serve to enhance its competitive position.

Environmental Matters The pipeline and energy services operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The Company believes it is in substantial compliance with those regulations.

Ongoing operations are subject to the Clean Air Act, the Clean Water Act, the NEPA, ESA and other state and federal regulations. Administration of many provisions of these laws has been delegated to the states where WBI Energy and its subsidiaries operate. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements are included in the FERC's permitting processes for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and energy services operations did not incur any material environmental expenditures in 2014 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017.

Exploration and Production

General Fidelity is involved in the development and production of oil and natural gas resources. The Company intends to market its exploration and production business in the future. The plan to market this business has been delayed due to low oil prices. Until such sale is accomplished, this segment will apply technology and utilize existing expertise to increase production and reserves from existing leaseholds. By optimizing existing operations, this segment is focused on balancing its oil and natural gas commodity mix to maximize profitability. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests.

For information regarding exploration and production litigation, see Item 8 - Note 19.

Fidelity's business is focused primarily in two core regions: Rocky Mountain and Mid-Continent/Gulf States.

Rocky Mountain

Fidelity's Rocky Mountain region includes the following significant operating areas:

- Bakken areas - Oil targets in which Fidelity holds approximately 12,000 net acres in Mountrail County, North Dakota and approximately 37,000 net acres in Stark County, North Dakota.
- Cedar Creek Anticline - Primarily in eastern Montana, the Company has a long-held net profits interest in this oil play.
- Paradox Basin - The Company holds approximately 140,000 net acres located in Grand and San Juan Counties, Utah, targeting oil, and has an option to earn another 20,000 acres.
- Powder River Basin - The Company holds primarily non-operated undeveloped leasehold positions of approximately 24,000 net acres in Converse County, Wyoming, which were acquired in 2014.
- Big Horn Basin - These interests include approximately 6,000 net acres in Wyoming, targeting oil and NGL.
- Baker Field - Long-held natural gas properties in which Fidelity holds approximately 98,000 net acres in southeastern Montana and southwestern North Dakota.
- Bowdoin Field - Long-held natural gas properties in which Fidelity holds approximately 127,000 net acres in north-central Montana.
- Other - Includes other oil projects and various non-operated positions.

Mid-Continent/Gulf States

Fidelity's Mid-Continent/Gulf States region includes the following significant operating areas:

- South Texas - Includes non-operated positions in approximately 1,000 net acres in the Flores field. This area has significant NGL content associated with the natural gas.
- East Texas - Fidelity holds approximately 9,000 net acres, primarily natural gas and associated NGL.
- Other - Includes various non-operated onshore interests, as well as offshore interests in the shallow waters off the coasts of Texas and Louisiana.

Operating Information Annual net production by region for 2014 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	4,681	256	15,704	7,554	84%
Mid-Continent/Gulf States	238	353	5,118	1,444	16
Total	4,919	609	20,822	8,998	100%

Note: Bakken-Mountrail County represents 36% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2014.

Annual net production by region for 2013 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	4,481	250	19,461	7,975	78%
Mid-Continent/Gulf States	334	531	8,547	2,289	22
Total	4,815	781	28,008	10,264	100%

Note: Bakken-Mountrail County represents 43% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2013.

Annual net production by region for 2012 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	3,295	249	23,180	7,408	74%
Mid-Continent/Gulf States	399	579	10,034	2,650	26
Total	3,694	828	33,214	10,058	100%

Note: Bakken-Mountrail County represents 47% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2012.

Well and Acreage Information Gross and net productive well counts and gross and net developed and undeveloped acreage related to Fidelity's interests at December 31, 2014, were as follows:

	Gross *	Net **
Productive wells:		
Oil	924	195
Natural gas	2,075	1,580
Total	2,999	1,775
Developed acreage (000's)	527	328
Undeveloped acreage set to expire in the years (000's):		
2015	141	80
2016	23	12
2017	5	5
Thereafter	569	276
Total undeveloped acreage	738	373

* Reflects well or acreage in which an interest is owned.
** Reflects Fidelity's percentage of ownership.

In most cases, acreage set to expire can be held through drilling operations or the Company can exercise extension options.

Delivery Commitments At December 31, 2014, Fidelity has commitments to deliver fixed and determinable amounts of oil under contract for all of its Mountrail County production for the first quarter of 2015. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of natural gas at December 31, 2014.

Exploratory and Development Wells The following table reflects activities related to Fidelity's oil and natural gas wells drilled and/or tested during 2014, 2013 and 2012:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2014	**—**	**1**	**1**	**20**	**1**	**21**	**22**
2013	3	2	5	35	3	38	43
2012	24	3	27	39	1	40	67

At December 31, 2014, there were 28 gross (8 net) wells in the process of drilling or under evaluation, all of which were development wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of these wells within the next 12 months.

The information in the preceding table should not be considered indicative of future performance nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons whether or not they produce a reasonable rate of return.

Competition The exploration and production industry is highly competitive. Fidelity competes with a substantial number of major and independent exploration and production companies in securing the equipment, services and expertise necessary to develop and operate its properties.

Environmental Matters Fidelity's operations are generally subject to federal, state and local environmental and operational laws and regulations. Fidelity believes it is in substantial compliance with these regulations.

The ongoing operations of Fidelity are subject to the Clean Air Act, the Clean Water Act, the NEPA, ESA and other state, federal and local regulations. Administration of many provisions of these laws has been delegated to the states where Fidelity operates. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements under federal and state laws are required as part of the permitting process covering the conduct of drilling and production operations as well as in the abandonment and reclamation of facilities.

In connection with production operations, Fidelity has not incurred any material capital environmental expenditures in 2014 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017.

Proved Reserve Information Estimates of proved oil, NGL and natural gas reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. Other factors used in the proved reserve estimates are prices, market differentials, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The proved reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in mathematics with a technical minor in petroleum engineering, has 27 years of experience in petroleum engineering and reserve estimation, and is a member of the Society of Petroleum Engineers. In addition, the Company engages an independent third party to audit its proved reserves. Ryder Scott reviewed the Company's proved reserve quantity estimates as of December 31, 2014. The technical person at Ryder Scott primarily responsible for overseeing the reserves audit is a Senior Vice President with over 30 years of experience in estimating and auditing reserves attributable to oil and gas properties, holds a bachelor of science degree in mechanical engineering, is a registered professional engineer, and is a member of multiple professional organizations.

Fidelity's proved reserves by region at December 31, 2014, are as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	PV-10 Value (in millions) *
Rocky Mountain	42,018	2,865	160,866	71,694	78%	$ 1,288.5
Mid-Continent/Gulf States	1,900	4,322	84,145	20,246	22	140.8
Total proved reserves	43,918	7,187	245,011	91,940	100%	1,429.3
Discounted future income taxes						354.4
Standardized measure of discounted future net cash flows relating to proved reserves						$ 1,074.9

* Pre-tax PV-10 value is a non-GAAP financial measure that is derived from the most directly comparable GAAP financial measure which is the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows disclosed in Item 8 - Supplementary Financial Information, is presented after deducting discounted future income taxes, whereas the PV-10 value is presented before income taxes. Pre-tax PV-10 value is commonly used by the Company to evaluate properties that are acquired and sold and to assess the potential return on investment in the Company's oil and natural gas properties. The Company believes pre-tax PV-10 value is a useful supplemental disclosure to the standardized measure as the Company believes readers may utilize this value as a basis for comparison of the relative size and value of the Company's reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. However, pre-tax PV-10 value is not a substitute for the standardized measure of discounted future net cash flows. Neither the pre-tax PV-10 value nor the standardized measure of discounted future net cash flows purports to represent the fair value of the Company's oil and natural gas properties.

For more information related to oil and natural gas interests, see Item 8 - Note 1 and Supplementary Financial Information.

Construction Materials and Contracting

General Knife River operates construction materials and contracting businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix and supply ready-mixed concrete for use in most types of construction, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Although not common to all locations, other products include the sale of cement, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services.

For information regarding construction materials litigation, see Item 8 - Note 19.

The construction materials business had approximately $438 million in backlog at December 31, 2014, compared to $456 million at December 31, 2013. The Company anticipates that a significant amount of the current backlog will be completed during 2015.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Price is the principal competitive force to which these products are subject, with service, quality, delivery time and proximity to the customer also being significant factors. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending, general economic conditions within the market area that influence both the commercial and residential sectors, and prevailing interest rates.

Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its construction materials businesses.

Reserve Information Aggregate reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine high walls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory-type properties.

Estimates are based on analyses of the data described above by experienced internal mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described previously are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

Topography associated with the hard rock reserves is typically much more diverse. Therefore, using available data, a final topography map is created and computer software is utilized to compute the volumes between the existing and final topographies. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 2 tons per cubic yard in the ground is used for hard rock quarries.

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 1.0 billion tons of the 1.1 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales from 2012 through 2014. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

The following table sets forth details applicable to the Company's aggregate reserves under ownership or lease as of December 31, 2014, and sales for the years ended December 31, 2014, 2013 and 2012:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Production Area	owned	leased	owned	leased	**2014**	2013	2012			
Anchorage, AK	—	—	1	—	**1,665**	1,074	110	19,153	N/A	20
Hawaii	—	6	—	—	**1,840**	1,672	1,678	55,493	2017-2064	32
Northern CA	—	—	9	1	**1,340**	1,525	1,203	53,784	2018	40
Southern CA	—	2	—	—	**147**	241	784	91,963	2035	Over 100
Portland, OR	1	3	5	3	**3,244**	3,343	2,698	228,710	2025-2055	74
Eugene, OR	3	4	4	1	**928**	825	847	167,464	2016-2046	Over 100
Central OR/WA/ID	1	1	5	4	**1,254**	1,045	1,131	115,361	2020-2077	Over 100
Southwest OR	5	4	11	6	**1,624**	1,465	1,613	95,586	2017-2053	61
Central MT	—	—	1	2	**1,260**	1,236	1,200	27,173	2023-2027	22
Northwest MT	—	—	7	2	**1,486**	1,242	1,011	64,538	2016-2020	52
Wyoming	—	—	1	1	**952**	983	428	10,619	2019	13
Central MN	—	1	36	20	**1,674**	1,578	1,714	64,058	2015-2028	39
Northern MN	2	—	18	5	**491**	349	195	26,896	2015-2017	78
ND/SD	—	—	7	14	**2,377**	1,862	1,711	29,099	2015-2031	15
Texas	1	—	1	—	**903**	672	692	11,259	2022	15
Sales from other sources					**4,642**	5,601	6,270			
					25,827	24,713	23,285	1,061,156		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2014, are comprised of 497 million tons that are owned and 564 million tons that are leased. Approximately 48 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 24 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2012 through 2014 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 69 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

The changes in Knife River's aggregate reserves for the years ended December 31 are as follows:

	2014	2013	2012
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,083,376**	1,088,236	1,088,833
Acquisitions	**12,343**	22,682	950
Sales volumes*	**(21,185)**	(19,112)	(17,320)
Other**	**(13,378)**	(8,430)	15,773
End of year	**1,061,156**	1,083,376	1,088,236

* Excludes sales from other sources.
** Includes property sales and revisions of previous estimates.

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as to the issues described later, Knife River believes it is in substantial compliance with these regulations. Individual permits applicable to Knife River's various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance and reporting procedures.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

Some Knife River activities are directly regulated by federal agencies. For example, certain in-water mining operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River operates several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated permits as required. The expiration dates of these permits vary, with five years generally being the longest term.

Knife River's operations also are occasionally subject to the ESA. For example, land use regulations often require environmental studies, including wildlife studies, before a permit may be granted for a new or expanded mining facility or an asphalt or concrete plant. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations also are subject to state and federal cultural resources protection laws when new areas are disturbed for mining operations or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can even be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in land use permit application review procedures in the counties where Knife River operates. After taking into account environmental, mine plan and reclamation information provided by the permittee as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare, but land use permits often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Knife River has been successful in obtaining mining and other land use permit approvals so that sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate reserve is needed to support Knife River's operations.

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the Surface Mining Control and Reclamation Act, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible.

Knife River did not incur any material environmental expenditures in 2014 and, except as to what may be ultimately determined with regard to the issues described later, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2017.

In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River - Northwest in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For more information, see Item 8 - Note 19.

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information. For more information, see Item 4 - Mine Safety Disclosures.

Construction Services

General MDU Construction Services specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather.

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2014, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2014, was approximately $305 million compared to $459 million at December 31, 2013. MDU Construction Services expects to complete a significant amount of this backlog during 2015. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, will be factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes that the diversification of the services it provides, the markets it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

Environmental Matters MDU Construction Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. MDU Construction Services believes it is in substantial compliance with these regulations.

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2014 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks

The Company's exploration and production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, that are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; domestic and foreign supplies of oil, NGL and natural gas; political and economic conditions in oil producing countries; actions of the

Organization of Petroleum Exporting Countries; drilling successes in oil and natural gas operations; the timely receipt of necessary permits and approvals; the ability to retain employees to identify, drill for and develop reserves; utilizing appropriate technologies; irregularities in geological formations; and other risks incidental to the development and operations of oil and natural gas wells, processing plants and pipeline systems. Continued prolonged depressed prices for oil, NGL and natural gas could impede the growth of our pipeline and energy services business, and could negatively affect the results of operations, cash flows and asset values of the Company's exploration and production and pipeline and energy services businesses.

Actual quantities of recoverable oil, NGL and natural gas reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts. There is a risk that changes in estimates of proved reserve quantities or other factors including low oil and natural gas prices, could result in future noncash write-downs of the Company's oil and natural gas properties.

The process of estimating oil, NGL and natural gas reserves is complex. Reserve estimates are based on assumptions relating to oil, NGL and natural gas pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the properties. The proved reserve estimates are prepared for each of the Company's properties by internal engineers assigned to an asset team by geographic area. The internal engineers analyze available geological, geophysical, engineering and economic data for each geographic area. The internal engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although the Company has prepared its proved reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the proved reserve estimates may occur based on actual results of production, drilling, costs and pricing.

The Company bases the estimated discounted future net cash flows from proved reserves on prices and current costs in accordance with SEC requirements. Actual future prices and costs may be significantly different. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter in 2014 were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
December 31, 2014	$ 94.99	$ 4.34	$ 7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47
March 31, 2014	98.46	3.99	7.33

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
January 2015	$ 53.27	$ 3.00	$ 3.06
February 2015	48.24	2.68	2.78

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

The regulatory approval, permitting, construction, startup and/or operation of power generation facilities and Dakota Prairie Refinery may involve unanticipated events or delays that could negatively impact the Company's business and its results of operations and cash flows.

The construction, startup and operation of power generation facilities and Dakota Prairie Refinery involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel and crude oil supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power, crude oil and refined products; cost increases and overruns; as well as the risk of performance below expected levels of output or efficiency. An additional risk for regulated projects would be the inability to obtain full cost recovery in regulated rates. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Economic volatility affects the Company's operations, as well as the demand for its products and services and the value of its investments and investment returns including its pension and other postretirement benefit plans, and may have a negative impact on the Company's future revenues and cash flows.

The global demand and price volatility for natural resources, interest rate changes, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could be adversely impacted by the economic conditions in the industries the Company serves, as well as in the economy in general. State and federal budget issues may negatively affect the funding available for infrastructure spending. The ability of the Company's electric and natural gas distribution businesses to grow service territory and customer base is affected by the economic environments of the markets served. This economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

Changing market conditions could negatively affect the market value of assets held in the Company's pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions.

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. If the Company is unable to obtain economic financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

The Company relies on access to short-term borrowings, including the issuance of commercial paper, long-term capital markets and asset sales as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks
- Cyber attacks

Economic turmoil, market disruptions and volatility in the securities trading markets, as well as other factors including changes in the Company's results of operations, financial position and prospects, may adversely affect the market price of the Company's common stock.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The issuance of a substantial amount of the Company's common stock, whether sold pursuant to the registration statement, issued in connection with an acquisition or otherwise, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

The Company is exposed to credit risk and the risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties.

If the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

The backlogs at the Company's construction materials and contracting and construction services businesses are subject to delay or cancellation and may not be realized.

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in the Company's backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control. Accordingly, there is no assurance that backlog will be realized.

Environmental and Regulatory Risks

The Company's operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to environmental laws and regulations affecting many aspects of its operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can increase capital, operating and other costs, cause delays as a result of litigation and administrative proceedings, and create compliance, remediation, containment, monitoring and reporting obligations, particularly relating to electric generation operations and oil and natural gas development and processing. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome (financial or operational) of any such litigation or administrative proceedings.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities, restrict the use of certain fuels, install pollution controls, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations that increase compliance costs or restrict operations, particularly if costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

In December 2011, the EPA finalized the Mercury and Air Toxics Standards rules that will require reductions in mercury and other air emissions from coal- and oil-fired electric utility steam generating units. Montana-Dakota evaluated the pollution control technologies needed at its electric generation resources to comply with this rule and determined that the Lewis & Clark Station near Sidney, Montana, will require additional particulate matter control for non-mercury metal emissions. Montana-Dakota has further evaluated pollution control options and intends to comply with the rule by making scrubber modifications, including installation of a mist eliminator and sieve tray. Controls must be in place by April 16, 2015, or April 16, 2016, if a one-year extension is granted for completion of the pollution control project. Because a one-year extension is needed to install the pollution control project, Montana-Dakota submitted a timely request for approval of a one-year compliance extension to the Montana DEQ on November 24, 2014. On January 30, 2015, the Montana DEQ approved the one-year extension.

On August 15, 2014, the EPA published a final rule under Section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric generating facilities are either not subject to the rule requirements or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study by 2018 that will be used to determine any required controls. It is unknown at this time what controls are required or if compliance costs will be material. The installation schedule for any required controls would be established with the permitting agency after the study is completed.

Hydraulic fracturing is an important common practice used by Fidelity that involves injecting water, sand, a water-thickening agent called guar, and trace amounts of chemicals, under pressure, into rock formations to stimulate oil, NGL and natural gas production. Fidelity follows state regulations for well drilling and completion, including regulations for hydraulic fracturing and recovered fluids disposal. Fracturing fluid constituents are reported on state or national websites. The EPA is developing a study to review potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study could impact future legislation or regulation. The BLM has released draft well stimulation regulations for hydraulic fracturing operations. If implemented, the BLM regulations would affect only Fidelity's operations on BLM-administered lands. If adopted as proposed, the BLM regulations, along with other legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies that focus on the hydraulic fracturing process, could result in additional compliance, reporting and disclosure requirements. Future legislation or regulation could increase compliance and operating costs, as well as delay or inhibit the Company's ability to develop its oil, NGL and natural gas reserves.

On August 16, 2012, the EPA published a final NSPS rule for the oil and natural gas industry. The NSPS rule phases in over two years. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the new rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high-efficiency device. Additional reporting requirements and control devices covering oil and natural gas production equipment were phased in for certain new oil and gas facilities effective January 2015. This new rule's impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream are not expected to be material and are likely to include implementing recordkeeping, reporting and testing requirements and purchasing and installing required equipment.

Initiatives to reduce GHG emissions could adversely impact the Company's operations.

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. On June 25, 2013, President Obama released his Climate Action Plan for the U.S. in which he stated his goal to reduce GHG emissions "in the range of 17 percent" below 2005 levels by 2020. The president issued a memorandum to the EPA on the same day, instructing the EPA to re-propose the GHG NSPS rule for new electric generation units. The EPA released the re-proposed rule on January 8, 2014, in the Federal Register, which takes the place of the rule proposed in 2012 for new electric generation units that the EPA did not finalize. This rule applies to new fossil fuel-fired electric generation units, including coal-fired units, natural gas-fired combined-cycle units and natural gas-fired simple-cycle peaking units. The EPA's 1,100 pounds of carbon dioxide per MW hour emissions standard for coal-fired units does not allow any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered.

President Obama also directed the EPA to develop a GHG NSPS standard for existing fossil fuel-fired electric generation units by June 1, 2014, with finalization by June 1, 2015. On June 18, 2014, the EPA published in the Federal Register a proposed rule limiting carbon dioxide emissions from existing fossil fuel-fired electric generating units and a separate proposed rule limiting carbon dioxide emissions from existing units that are modified or reconstructed.

In the proposed rule for existing sources, the EPA requires carbon dioxide emission reductions from each state and instructs each state, or group of states that work together, to submit a plan to the EPA by June 30, 2016, that demonstrates how the state will achieve the targeted emission reductions by 2030. The state plans could include performance standards, emissions reductions or limits on generation for each existing fossil fuel-fired generating unit. It is unknown at this time what each state will require for emissions reductions from each Montana-Dakota owned and jointly owned fossil fuel-fired electric generating unit. In the EPA's proposed GHG rule for modified or reconstructed fossil fuel-fired sources, the EPA proposes emissions limits that could potentially be unachievable. Montana-Dakota does not plan to modify or reconstruct any fossil fuel-fired units at this time, but may modify or reconstruct units in the future which may require compliance with the rule limitations.

The Company's primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 60 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired facilities.

There may also be new treaties, legislation or regulations to reduce GHG emissions that could affect Montana-Dakota's electric utility operations by requiring additional energy conservation efforts or renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could adversely impact the results of its operations.

In addition to Montana-Dakota's electric generation operations, the GHG emissions from the Company's other operations are monitored, analyzed and reported as required by applicable laws and regulations. The Company monitors GHG regulations and the potential for GHG regulations to impact operations.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the potential financial impact on its operations.

The Company is subject to government regulations that may delay and/or have a negative impact on its business and its results of operations and cash flows. Statutory and regulatory requirements also may limit another party's ability to acquire the Company.

The Company is subject to regulation or governmental actions by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, industry rate structures, health care legislation, tax legislation and recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows. Approval from a number of federal and state regulatory agencies would need to be obtained by any potential acquirer of the Company. The approval process could be lengthy and the outcome uncertain.

Other Risks

Weather conditions can adversely affect the Company's operations, and revenues and cash flows.

The Company's results of operations can be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction materials and contracting and construction services businesses and affect ongoing operation and maintenance and construction and drilling activities for the pipeline and energy services and exploration and production businesses. In addition, severe weather can be destructive, causing outages, reduced oil and natural gas production, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition is increasing in all of the Company's businesses.

All of the Company's businesses are subject to increased competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. Construction materials products are marketed under highly competitive conditions and are subject to such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also are experiencing increased competitive pressures as a result of consumer demands, technological advances, volatility in natural gas prices and other factors. The pipeline and energy services business competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The exploration and production business is subject to competition in the acquisition and development of oil and natural gas properties. The increase in competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company could be subject to limitations on its ability to pay dividends.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as capital requirements and the Company's financial performance or cash flows, could limit the earnings of the Company's divisions and subsidiaries which, in turn, could restrict the Company's ability to pay dividends on its common stock and adversely affect the Company's stock price.

An increase in costs related to obligations under MEPPs could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 85 MEPPs for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 40 percent of the MEPPs to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to MEPPs where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to MEPPs may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, actions taken by the plans' other participating employers, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to MEPPs, which may have a material adverse effect on the Company's results of operations, financial position or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.

On September 24, 2014, Knife River provided notice to the plan administrator of one of the MEPPs to which it is a participating employer that it was withdrawing from that plan effective October 26, 2014. The plan administrator will determine Knife River's withdrawal liability, which the Company currently estimates at approximately $14 million (approximately $8.4 million after tax). The assessed withdrawal liability for this plan may be significantly different from the current estimate.

The Company's operations may be negatively impacted by cyber attacks or acts of terrorism.

The Company operates in industries that require continual operation of sophisticated information technology systems and network infrastructure. While the Company has developed procedures and processes that are designed to strengthen and protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, viruses, acts of terrorism or other causes. If the technology systems were to fail or be breached and these systems were not recovered in a timely manner, the Company's operational systems and infrastructure, such as the Company's electric generation, transmission and distribution facilities and its oil and natural gas production, storage and pipeline systems, may be unable to fulfill critical business functions, including a loss of service to customers. Any such disruption could result in a decrease in the Company's revenues and/or significant remediation costs which could have a material adverse effect on the Company's results of operations, financial position and cash flows. Additionally, because generation, transmission systems and gas pipelines are part of an interconnected system, a disruption elsewhere in the system could negatively impact the Company's business.

The Company's business requires access to sensitive customer, employee and Company data in the ordinary course of business. Despite the Company's implementation of security measures, a failure or breach of a security system could compromise sensitive and confidential information and data. Such an event could result in negative publicity and reputational harm, remediation costs and possible legal claims and fines which could adversely affect the Company's financial results, notwithstanding the purchase of cyber risk insurance. The Company's third party service providers that perform critical business functions or have access to sensitive and confidential information and data may also be vulnerable to security breaches and other risks that could have an adverse effect on the Company.

While the Company plans to market and sell its exploration and production business, there is no assurance that it will be successful.

As part of the Company's corporate strategy, it plans to market and sell its exploration and production assets and exit that line of business. The Company has delayed its plan to market Fidelity in light of the recent volatility of oil prices. At such time as the marketing resumes, such a disposition and exit will be subject to various risks, including: suitable purchasers may not be available or willing to purchase the assets on terms and conditions acceptable to the Company or may only be interested in acquiring a portion of the assets; the agreements pursuant to which the Company divests the assets may contain continuing indemnification obligations; the inability to obtain waivers from applicable covenants under debt agreements; the Company may incur substantial costs in connection with the marketing and sale of the assets; the marketing and sale of the assets could distract management, divert resources, disrupt the Company's ongoing business and make it difficult for the Company to maintain its current business standards, controls and procedures; uncertainties associated with the sale may cause a loss of key management personnel at Fidelity which could make it more difficult to sell the assets or operate the business in the event that the Company is unable to sell it; sale of the assets could result in substantial tax liability; the Company may be required to record an impairment charge that could have an adverse effect on the Company's financial condition; and the Company may not be able to redeploy the proceeds from any sale of the assets in a manner that produces similar revenues and growth rates or enhances shareholder value.

Other factors that could impact the Company's businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the Company. These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The ability to obtain adequate and timely cost recovery for the Company's regulated operations through regulatory proceedings
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- The cyclical nature of large construction projects at certain operations
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs, including related energy costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- Inability of the various contract counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology

- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs and funding requirements

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings, see Item 8 - Note 19, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-K, which is incorporated herein by reference.

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2014 and 2013 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2014			
First quarter	**$35.10**	**$29.62**	**$.1775**
Second quarter	**36.05**	**32.45**	**.1775**
Third quarter	**35.41**	**27.35**	**.1775**
Fourth quarter	**28.51**	**21.33**	**.1825**
			$.7150
2013			
First quarter	$25.00	$21.50	$.1725
Second quarter	27.14	23.37	.1725
Third quarter	30.21	25.94	.1725
Fourth quarter	30.97	27.53	.1775
			$.6950

As of December 31, 2014, the Company's common stock was held by approximately 13,300 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 12.

The following table includes information with respect to the Company's purchase of equity securities:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2014	—			
November 1 through November 30, 2014	40,506	$25.34		
December 1 through December 31, 2014	2,582	23.56		
Total	43,088			

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item 6. Selected Financial Data

	2014	2013	2012 (a)	2011	2010	2009 (b)
Selected Financial Data						
Operating revenues (000's):						
Electric	$ 277,874	$ 257,260	$ 236,895	$ 225,468	$ 211,544	$ 196,171
Natural gas distribution	921,986	851,945	754,848	907,400	892,708	1,072,776
Pipeline and energy services	215,868	202,068	193,157	278,343	329,809	307,827
Exploration and production	547,571	536,023	448,617	453,586	434,354	439,655
Construction materials and contracting	1,765,330	1,712,137	1,617,425	1,510,010	1,445,148	1,515,122
Construction services	1,119,529	1,039,839	938,558	854,389	789,100	819,064
Other	9,364	9,620	10,370	11,446	7,727	9,487
Intersegment eliminations	(186,964)	(146,488)	(124,439)	(190,150)	(200,695)	(183,601)
	$ 4,670,558	$ 4,462,404	$ 4,075,431	$ 4,050,492	$ 3,909,695	$ 4,176,501
Operating income (loss) (000's):						
Electric	$ 61,331	$ 54,274	$ 49,852	$ 49,096	$ 48,296	$ 36,709
Natural gas distribution	65,633	78,829	67,579	82,856	75,697	76,899
Pipeline and energy services	37,616	20,046	49,139	45,365	46,310	69,388
Exploration and production	158,229	161,402	(276,642)	133,790	143,169	(473,399)
Construction materials and contracting	86,462	93,629	57,864	51,092	63,045	93,270
Construction services	82,309	85,246	66,531	39,144	33,352	44,255
Other	5,734	6,649	4,884	5,024	858	(219)
Intersegment eliminations	(9,089)	(7,176)	—	—	—	—
	$ 488,225	$ 492,899	$ 19,207	$ 406,367	$ 410,727	$ (153,097)
Earnings (loss) on common stock (000's):						
Electric	$ 36,731	$ 34,837	$ 30,634	$ 29,258	$ 28,908	$ 24,099
Natural gas distribution	30,484	37,656	29,409	38,398	36,944	30,796
Pipeline and energy services	22,628	7,629	26,588	23,082	23,208	37,845
Exploration and production	96,733	94,450	(177,283)	80,282	85,638	(296,730)
Construction materials and contracting	51,510	50,946	32,420	26,430	29,609	47,085
Construction services	54,432	52,213	38,429	21,627	17,982	25,589
Other	7,461	5,136	4,797	6,190	21,046	7,357
Intersegment eliminations	(5,608)	(4,307)	—	—	—	—
Earnings (loss) on common stock before income (loss) from discontinued operations	294,371	278,560	(15,006)	225,267	243,335	(123,959)
Income (loss) from discontinued operations, net of tax	3,177	(312)	13,567	(12,926)	(3,361)	—
	$ 297,548	$ 278,248	$ (1,439)	$ 212,341	$ 239,974	$ (123,959)
Earnings (loss) per common share before discontinued operations - diluted	$ 1.53	$ 1.47	$ (.08)	$ 1.19	$ 1.29	$ (.67)
Discontinued operations, net of tax	.02	—	.07	(.07)	(.02)	—
	$ 1.55	$ 1.47	$ (.01)	$ 1.12	$ 1.27	$ (.67)
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	192,587	189,693	188,826	188,905	188,229	185,175
Dividends declared per common share	$ .7150	$ .6950	$ .6750	$ .6550	$ .6350	$ .6225
Book value per common share	$ 16.66	$ 15.01	$ 13.95	$ 14.62	$ 14.22	$ 13.61
Market price per common share (year end)	$ 23.50	$ 30.55	$ 21.24	$ 21.46	$ 20.27	$ 23.60
Market price ratios:						
Dividend payout	46%	47%	(c)	58%	50%	(c)
Yield	3.1%	2.3%	3.2%	3.1%	3.2%	2.7%
Market value as a percent of book value	141.1%	203.5%	152.3%	146.8%	142.5%	173.4%

(a) Reflects $246.8 million of after-tax noncash write-downs of oil and natural gas properties.
(b) Reflects a $384.4 million after-tax noncash write-down of oil and natural gas properties.
(c) Not meaningful due to effects of the after-tax noncash write-down(s), as previously discussed.

Item 6. Selected Financial Data (continued)

	2014	2013	2012	2011	2010	2009
General						
Total assets (000's)	$ 7,809,978	$ 7,061,332	$ 6,682,491	$ 6,556,125	$ 6,303,549	$ 5,990,952
Total long-term debt (000's)	$ 2,094,727	$ 1,854,563	$ 1,744,975	$ 1,424,678	$ 1,506,752	$ 1,499,306
Capitalization ratios:						
Common equity	61%	60%	60%	66%	64%	63%
Total debt	39	40	40	34	36	37
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	3,308,358	3,173,086	2,996,528	2,878,852	2,785,710	2,663,560
Electric system summer and firm purchase contract ZRCs (Interconnected system)	584.0	583.5	552.8	572.8	553.3	(a)
Electric system peak demand obligation, including firm purchase contracts, ZRCs (Interconnected system)	522.4	508.3	550.7	524.2	529.5	(a)
Demand peak - kW (Interconnected system)	582,083	573,587	573,587	535,761	525,643	525,643
Electricity produced (thousand kWh)	2,519,938	2,430,001	2,299,686	2,488,337	2,472,288	2,203,665
Electricity purchased (thousand kWh)	1,010,422	971,261	870,516	645,567	521,156	682,152
Average cost of fuel and purchased power per kWh	$ .025	$ .025	$ .023	$ .021	$ .021	$ .023
Natural Gas Distribution						
Sales (Mdk)	104,297	108,260	93,810	103,237	95,480	102,670
Transportation (Mdk)	145,941	149,490	132,010	124,227	135,823	132,689
Degree days (% of normal)						
Montana-Dakota/Great Plains	103%	105%	84%	101%	98%	104%
Cascade	89%	98%	96%	103%	96%	105%
Intermountain	95%	110%	91%	107%	100%	107%
Pipeline and Energy Services						
Transportation (Mdk)	233,483	178,598	137,720	113,217	140,528	163,283
Gathering (Mdk)	38,372	40,737	47,084	66,500	77,154	92,598
Customer natural gas storage balance (Mdk)	14,885	26,693	43,731	36,021	58,784	61,506
Exploration and Production						
Production:						
Oil (MBbls)	4,919	4,815	3,694	2,724	2,767	2,557
NGL (MBbls)	609	781	828	776	495	554
Natural gas (MMcf)	20,822	28,008	33,214	45,598	50,391	56,632
Total production (MBOE)	8,998	10,264	10,058	11,099	11,661	12,550
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):						
Oil (per Bbl)	$ 83.33	$ 89.70	$ 84.84	$ 91.62	$ 70.61	$ 53.57
NGL (per Bbl)	$ 36.06	$ 37.39	$ 39.81	$ 54.06	$ 44.93	$ 32.18
Natural gas (per Mcf)	$ 4.02	$ 2.89	$ 2.08	$ 3.30	$ 3.57	$ 2.99
Average realized prices (including realized gain/loss on commodity derivatives):						
Oil (per Bbl)	$ 85.96	$ 89.35	$ 86.54	$ 86.20	$ 69.59	$ 50.67
NGL (per Bbl)	$ 36.06	$ 37.39	$ 39.81	$ 54.06	$ 44.93	$ 32.18
Natural gas (per Mcf)	$ 3.81	$ 2.96	$ 2.91	$ 3.84	$ 4.36	$ 5.16
Proved reserves:						
Oil (MBbls)	43,918	41,019	33,453	27,005	25,666	25,930
NGL (MBbls)	7,187	6,602	7,153	7,342	7,201	8,286
Natural gas (MMcf)	245,011	198,445	239,278	379,827	448,397	448,425
Total proved reserves (MBOE)	91,940	80,695	80,486	97,651	107,599	108,954
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	25,827	24,713	23,285	24,736	23,349	23,995
Asphalt (tons)	6,070	6,228	5,988	6,709	6,279	6,360
Ready-mixed concrete (cubic yards)	3,460	3,223	3,157	2,864	2,764	3,042
Aggregate reserves (000's tons)	1,061,156	1,083,376	1,088,236	1,088,833	1,107,396	1,125,491

(a) Information not available for periods prior to 2010.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and return on invested capital
- Divestiture of certain assets to fund capital growth projects throughout the Company

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities, the issuance from time to time of debt and equity securities and asset sales. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see Item 8 - Note 15.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide safe and reliable competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and timely recovery and permitted returns on investment as well as subject to certain operational, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities are subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas.

Pipeline and Energy Services

Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, investments in and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; incremental expansion of pipeline capacity; expansion of midstream business to include liquid pipelines and processing/refining activities; and expansion of related energy services.

Challenges Challenges for this segment include: energy price volatility; tight natural gas basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and energy services companies.

Exploration and Production

Strategy The Company intends to market and sell its exploration and production business. However, the Company has delayed its plan in light of the recent volatility in oil prices. Until such sale is accomplished, this segment will apply technology and utilize existing expertise to increase production and reserves from existing leaseholds. By optimizing existing operations, this segment is focused on balancing its oil and natural gas commodity mix to maximize profitability.

Challenges Risks and uncertainties associated with the marketing and sale of the Fidelity assets; current oil and natural gas low-price environment; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; utilizing appropriate technologies; inflationary pressure on development and operating costs; irregularities in geological formations; and competition from other exploration and production companies are ongoing challenges for this segment.

Construction Materials and Contracting

Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Recruitment and retention of key personnel and volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, continue to be a concern. This business unit expects to continue cost containment efforts, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

Construction Services

Strategy Provide a superior return on investment by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; continue growth through organic and acquisition opportunities; and focusing our efforts on projects that will permit higher margins while properly managing risk.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

For more information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A - Risk Factors. For more information on key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Item 8 - Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings (loss) by each of the Company's businesses.

Years ended December 31,	2014	2013	2012
	(Dollars in millions, where applicable)		
Electric	$ **36.7**	$ 34.8	$ 30.6
Natural gas distribution	**30.5**	37.7	29.4
Pipeline and energy services	**22.6**	7.6	26.6
Exploration and production	**96.8**	94.5	(177.2)
Construction materials and contracting	**51.5**	50.9	32.4
Construction services	**54.5**	52.2	38.4
Other	**7.5**	5.1	4.8
Intersegment eliminations	**(5.7)**	(4.3)	—
Earnings (loss) before discontinued operations	**294.4**	278.5	(15.0)
Income (loss) from discontinued operations, net of tax	**3.1**	(.3)	13.6
Earnings (loss) on common stock	$ **297.5**	$ 278.2	$ (1.4)
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	$ **1.53**	$ 1.47	$ (.08)
Discontinued operations, net of tax	**.02**	—	.07
Earnings (loss) per common share - basic	$ **1.55**	$ 1.47	$ (.01)
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	$ **1.53**	$ 1.47	$ (.08)
Discontinued operations, net of tax	**.02**	—	.07
Earnings (loss) per common share - diluted	$ **1.55**	$ 1.47	$ (.01)

2014 compared to 2013 Consolidated earnings for 2014 increased $19.3 million from the prior year. This increase was due to:

- The absence of the 2013 impairment of coalbed natural gas gathering assets of $9.0 million (after tax), as discussed in Item 8 - Note 1, as well as higher earnings due to increased transportation rates and higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets; partially offset by lower storage services earnings
- Other earnings and earnings from discontinued operations increased resulting from favorable income tax changes, due to the resolution of certain tax matters and higher income tax benefits

Partially offsetting these increases were higher operation and maintenance expense, higher depreciation, depletion and amortization expense and the absence of the 2013 $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business; partially offset by higher other income and natural gas retail sales margins at the natural gas distribution business.

2013 compared to 2012 Consolidated earnings for 2013 increased $279.6 million from the prior year. This increase was due to:

- Absence of the write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 - Note 1, increased oil production and higher average realized natural gas and oil prices, partially offset by a lower realized gain on commodity derivatives of $21.1 million (after tax), higher depreciation, depletion and amortization expense, decreased natural gas production, higher production taxes, as well as higher general and administrative expense at the exploration and production business
- Higher asphalt and aggregate margins and volumes at the construction materials and contracting business
- Higher workloads and margins in the Western and Central regions, as well as higher equipment sales and rental revenue and margins at the construction services business
- Increased retail sales volumes and a $2.8 million (after tax) gain on the sale of a nonregulated appliance service and repair business, partially offset by higher operation and maintenance expense, as well as higher depreciation, depletion and amortization expense at the natural gas distribution business

Partially offsetting these increases were:

- A net benefit in 2013 of $1.5 million (after tax) compared to $15.0 million (after tax) in 2012, related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19, as well as an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013 compared to an impairment of $1.7 million (after tax) in 2012, as discussed in Item 8 - Note 1, at the pipeline and energy services business
- Loss from discontinued operations of $300,000 (after tax) in 2013, compared to income from discontinued operations of $13.6 million (after tax) in 2012, primarily due to the absence in 2013 of a net benefit in 2012 related to the reversal of an arbitration charge resulting from a favorable court ruling, as discussed in Item 8 - Note 3

Financial and Operating Data

Following are key financial and operating data for each of the Company's businesses.

Electric

Years ended December 31,	2014	2013	2012
	(Dollars in millions, where applicable)		
Operating revenues	$ **277.9**	$ 257.3	$ 236.9
Operating expenses:			
Fuel and purchased power	**89.3**	83.5	72.4
Operation and maintenance	**81.1**	76.5	71.8
Depreciation, depletion and amortization	**35.0**	32.8	32.5
Taxes, other than income	**11.1**	10.2	10.3
	216.5	203.0	187.0
Operating income	**61.4**	54.3	49.9
Earnings	$ **36.7**	$ 34.8	$ 30.6
Retail sales (million kWh)	**3,308.4**	3,173.1	2,996.5
Average cost of fuel and purchased power per kWh	$ **.025**	$ .025	$ .023

2014 compared to 2013 Electric earnings increased $1.9 million (5 percent) compared to the prior year due to increased electric retail sales margins, primarily due to rate recovery on electric environmental upgrades and increased electric sales volumes of 4 percent to all customer classes, due to customer growth.

Partially offsetting the increase were:

- Higher operation and maintenance expense, which includes $3.5 million (after tax) largely related to higher benefit-related costs and increased contract services
- Higher net interest expense, which includes $1.8 million (after tax) due to higher long-term debt
- Higher depreciation, depletion and amortization expense of $1.4 million (after tax) due to increased property, plant and equipment balances

2013 compared to 2012 Electric earnings increased $4.2 million (14 percent) compared to the prior year due to:

- Higher electric retail sales margins, including the result of 6 percent higher volumes, primarily to residential, commercial and industrial customers due to increased residential customer growth and weather variances from last year
- Higher other income, largely higher allowance for funds used during construction of $800,000 (after tax)

These increases were partially offset by higher operation and maintenance expense, which includes $2.3 million (after tax) largely related to higher payroll-related costs and increased contract services, offset in part by lower benefit-related costs.

Natural Gas Distribution

Years ended December 31,	2014	2013	2012
	(Dollars in millions, where applicable)		
Operating revenues	$ **922.0**	$ 851.9	$ 754.8
Operating expenses:			
Purchased natural gas sold	**603.2**	534.8	457.4
Operation and maintenance	**150.2**	142.3	139.4
Depreciation, depletion and amortization	**54.7**	50.0	45.7
Taxes, other than income	**48.3**	46.0	44.7
	856.4	773.1	687.2
Operating income	**65.6**	78.8	67.6
Earnings	$ **30.5**	$ 37.7	$ 29.4
Volumes (MMdk):			
Sales	**104.3**	108.3	93.8
Transportation	**145.9**	149.5	132.0
Total throughput	**250.2**	257.8	225.8
Degree days (% of normal)*			
Montana-Dakota/Great Plains	**103%**	105%	84%
Cascade	**89%**	98%	96%
Intermountain	**95%**	110%	91%
Average cost of natural gas, including transportation, per dk	$ **5.78**	$ 4.94	$ 4.88

* Degree days are a measure of the daily temperature-related demand for energy for heating.

2014 compared to 2013 The natural gas distribution business experienced a decrease in earnings of $7.2 million (19 percent) compared to the prior year due to:

- Higher operation and maintenance expense, which includes $4.8 million (after tax) largely related to higher payroll and benefits-related costs
- Higher depreciation, depletion and amortization expense of $2.9 million (after tax), primarily resulting from increased property, plant and equipment balances
- The absence of the 2013 $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business

These decreases were partially offset by:

- Higher other income, which includes $2.1 million (after tax) largely related to allowance for funds used during construction
- Higher natural gas retail sales margins, primarily resulting from approved rate increases effective in late 2013, largely offset by lower sales volumes of 4 percent ($4.3 million after tax) in certain jurisdictions due to warmer weather than the prior year

2013 compared to 2012 The natural gas distribution business experienced an increase in earnings of $8.3 million (28 percent) compared to the prior year due to:

- Increased retail sales volumes of 15 percent, largely resulting from increased customer growth and colder weather than last year, partially offset by weather normalization adjustments in certain jurisdictions
- A $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business
- Lower net interest expense, which includes $2.3 million (after tax) largely related to lower average interest rates

These increases were partially offset by:

- Higher operation and maintenance expense, which includes $3.4 million (after tax) largely related to higher payroll-related costs, offset in part by lower benefit-related costs
- Increased depreciation, depletion and amortization expense of $2.7 million (after tax), primarily resulting from higher property, plant and equipment balances
- Lower other income, which includes $2.0 million (after tax) largely related to lower allowance for funds used during construction

Pipeline and Energy Services

Years ended December 31,	2014	2013	2012
	(Dollars in millions)		
Operating revenues	$ **215.9**	$ 202.1	$ 193.1
Operating expenses:			
Purchased natural gas sold	**58.8**	57.5	50.5
Operation and maintenance*	**75.4**	81.8	52.2
Depreciation, depletion and amortization	**30.7**	29.1	27.7
Taxes, other than income	**13.4**	13.6	13.6
	178.3	182.0	144.0
Operating income	**37.6**	20.1	49.1
Earnings*	$ **22.6**	$ 7.6	$ 26.6
Transportation volumes (MMdk)	**233.5**	178.6	137.7
Natural gas gathering volumes (MMdk)	**38.4**	40.7	47.1
Customer natural gas storage balance (MMdk):			
Beginning of period	**26.7**	43.7	36.0
Net injection (withdrawal)	**(11.8)**	(17.0)	7.7
End of period	**14.9**	26.7	43.7

*Reflects an impairment of coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax) in second quarter 2013 and $2.7 million ($1.7 million after tax) in second quarter 2012, as well as a net benefit of $2.5 million ($1.5 million after tax) in fourth quarter 2013 and $24.1 million ($15.0 million after tax) in second quarter 2012 related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Item 8 - Note 19.

2014 compared to 2013 Pipeline and energy services earnings increased $15.0 million (197 percent) largely due to:

- Absence of the 2013 impairment of coalbed natural gas gathering assets of $9.0 million (after tax), as discussed in Item 8 - Note 1
- Higher earnings of $5.6 million (after tax) due to increased transportation rates, primarily due to a rate case settlement, and higher volumes
- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, primarily due to higher volumes
- Favorable income tax changes, including $1.8 million of higher income tax benefits

Partially offsetting the earnings increase were:

- Lower storage services earnings of $3.5 million (after tax), largely due to lower average storage balances and lower rates
- Higher operation and maintenance expense (excluding the asset impairment, net benefit related to natural gas gathering operations litigation and Pronghorn-related expense), which includes $1.6 million (after tax) largely payroll and benefits-related due to start-up costs related to Dakota Prairie Refinery
- Absence of the net benefit in 2013 of $1.5 million (after tax) related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19

2013 compared to 2012 Pipeline and energy services earnings decreased $19.0 million (71 percent) largely due to:

- A net benefit in 2013 of $1.5 million (after tax) compared to $15.0 million (after tax) in 2012, related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19
- An impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013, compared to an impairment of $1.7 million (after tax) in 2012, largely resulting from lower natural gas prices, as discussed in Item 8 - Note 1
- Lower storage services revenue of $3.1 million (after tax), primarily due to lower average rates and lower storage balances
- Lower earnings of $3.1 million (after tax) resulting from lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing production curtailments, normal declines and deferral of natural gas development activity

Partially offsetting the earnings decrease were:

- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, which were acquired in May 2012, primarily due to higher volumes
- Lower operation and maintenance expense (excluding the asset impairments, net benefits related to the natural gas gathering operations litigation and Pronghorn-related expense), which includes $2.0 million (after tax), largely related to lower payroll-related costs, legal and contract services
- Lower depreciation, depletion and amortization expense (excluding depreciation on Pronghorn oil and natural gas gathering and processing assets), which includes $1.6 million (after tax), primarily related to the coalbed areas

Exploration and Production

Years ended December 31,	2014	2013	2012
	(Dollars in millions, where applicable)		
Operating revenues:			
Oil	$ 409.9	$ 431.9	$ 313.4
NGL	22.0	29.2	33.0
Natural gas	83.8	81.0	69.2
Realized gain on commodity derivatives	8.5	.2	33.6
Unrealized gain (loss) on commodity derivatives	23.4	(6.3)	(.6)
	547.6	536.0	448.6
Operating expenses:			
Operation and maintenance:			
Lease operating costs	88.2	82.2	77.7
Gathering and transportation	12.5	15.4	17.4
Other	43.3	42.9	37.0
Depreciation, depletion and amortization	198.1	186.4	160.7
Taxes, other than income:			
Production and property taxes	46.1	46.6	39.7
Other	1.1	1.1	1.0
Write-downs of oil and natural gas properties	—	—	391.8
	389.3	374.6	725.3
Operating income (loss)	158.3	161.4	(276.7)
Earnings (loss)	$ 96.8	$ 94.5	$ (177.2)
Production:			
Oil (MBbls)	4,919	4,815	3,694
NGL (MBbls)	609	781	828
Natural gas (MMcf)	20,822	28,008	33,214
Total production (MBOE)	8,998	10,264	10,058
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):			
Oil (per Bbl)	$ 83.33	$ 89.70	$ 84.84
NGL (per Bbl)	$ 36.06	$ 37.39	$ 39.81
Natural gas (per Mcf)	$ 4.02	$ 2.89	$ 2.08
Average realized prices (including realized gain/loss on commodity derivatives):			
Oil (per Bbl)	$ 85.96	$ 89.35	$ 86.54
NGL (per Bbl)	$ 36.06	$ 37.39	$ 39.81
Natural gas (per Mcf)	$ 3.81	$ 2.96	$ 2.91
Average depreciation, depletion and amortization rate, per BOE	$ 21.17	$ 17.41	$ 15.28
Production costs, including taxes, per BOE:			
Lease operating costs	$ 9.80	$ 8.01	$ 7.73
Gathering and transportation	1.38	1.50	1.73
Production and property taxes	5.12	4.54	3.94
	$ 16.30	$ 14.05	$ 13.40

2014 compared to 2013 Earnings at the exploration and production business increased $2.3 million (2 percent) due to:

- Higher average realized natural gas prices of 39 percent, excluding gain/loss on commodity derivatives
- Unrealized gain on commodity derivatives of $14.7 million (after tax) in 2014 compared to an unrealized loss on commodity derivatives of $3.9 million (after tax) in 2013
- Increased oil production of 2 percent, primarily related to the Powder River Basin acquisition and drilling activity in the Paradox Basin
- Higher realized gain on commodity derivatives of $5.2 million (after tax), due to lower commodity prices relative to hedge prices
- Favorable income tax changes related to the resolution of certain income tax matters and higher income tax benefits
- Lower gathering and transportation expense of $1.8 million (after tax), largely due to lower gathering costs resulting from lower volumes

Partially offsetting these increases were:

- Lower average realized oil prices of 7 percent, excluding gain/loss on commodity derivatives
- Decreased natural gas production of 26 percent, largely due to the sale of non-strategic assets
- Higher depreciation, depletion and amortization expense of $7.4 million (after tax), due to higher depletion rates, offset in part by lower volumes
- Decreased NGL production of 22 percent, largely due to the sale of non-strategic assets
- Higher lease operating expenses of $3.8 million (after tax), primarily in the Paradox Basin

2013 compared to 2012 Earnings at the exploration and production business increased $271.7 million due to:

- Absence of the write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 - Note 1
- Increased oil production of 30 percent, primarily related to drilling activity in the Bakken and Paradox Basin areas
- Higher average realized natural gas prices of 39 percent, excluding gain/loss on commodity derivatives
- Higher average realized oil prices of 6 percent, excluding gain/loss on commodity derivatives

Partially offsetting these increases were:

- Lower realized gain on commodity derivatives of $21.1 million (after tax), due to higher commodity prices relative to hedge prices
- Higher depreciation, depletion and amortization expense of $16.2 million (after tax), largely due to higher depletion rates
- Decreased natural gas production of 16 percent, largely related to production curtailments, normal declines and deferral of certain natural gas development activity
- Higher production taxes of $4.3 million (after tax), primarily resulting from higher revenues
- Unrealized loss on commodity derivatives of $3.9 million (after tax) in 2013, compared to $400,000 (after tax) in 2012
- Higher general and administrative expense of $3.8 million (after tax), including higher payroll-related costs
- Higher net interest expense of $3.3 million (after tax), largely due to lower capitalized interest
- Increased lease operating expenses of $2.8 million (after tax), largely related to higher costs in the Bakken area resulting from increased production volumes and higher workover costs, as well as higher costs in the Paradox Basin resulting from increased production volumes, partially offset by lower costs at certain natural gas properties where curtailments of production have occurred

Construction Materials and Contracting

Years ended December 31,	2014	2013	2012
		(Dollars in millions)	
Operating revenues	$ 1,765.3	$ 1,712.1	$ 1,617.4
Operating expenses:			
Operation and maintenance*	1,571.5	1,505.2	1,442.5
Depreciation, depletion and amortization	68.6	74.5	79.5
Taxes, other than income	38.8	38.8	37.5
	1,678.9	1,618.5	1,559.5
Operating income	86.4	93.6	57.9
Earnings*	$ 51.5	$ 50.9	$ 32.4
Sales (000's):			
Aggregates (tons)	25,827	24,713	23,285
Asphalt (tons)	6,070	6,228	5,988
Ready-mixed concrete (cubic yards)	3,460	3,223	3,157

* Reflects a MEPP withdrawal liability of approximately $14 million ($8.4 million after tax). For more information, see Item 8 - Note 16.

2014 compared to 2013 Earnings at the construction materials and contracting business increased $600,000 (1 percent) due to:

- Favorable income tax changes, which includes $3.1 million related to the resolution of certain income tax matters and higher income tax benefits
- Higher earnings resulting from higher asphalt margins
- Higher earnings of $1.9 million (after tax) resulting from higher ready-mixed concrete volumes and margins

- Higher earnings of $1.7 million (after tax) resulting from higher aggregate margins and volumes
- Lower interest expense of $600,000 (after tax) due to lower average debt balances

Partially offsetting these increases were:

- A MEPP withdrawal liability of $8.4 million (after tax), as discussed in Item 8 - Note 16
- Higher selling, general and administrative expense of $1.9 million (after tax), primarily due to higher payroll and benefit-related costs

2013 compared to 2012 Earnings at the construction materials and contracting business increased $18.5 million (57 percent) due to:

- Higher earnings of $6.6 million (after tax) resulting from higher asphalt margins and volumes
- Higher earnings of $5.6 million (after tax) resulting from higher aggregate margins and volumes
- Lower selling, general and administrative costs of $2.4 million (after tax), largely lower insurance costs
- Higher earnings of $1.4 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Increased construction workloads and margins of $1.4 million (after tax)
- Higher earnings resulting from higher other product line volumes and margins

Partially offsetting the increases was higher interest expense of $1.3 million (after tax), resulting from higher average interest rates.

Construction Services

Years ended December 31,	2014	2013	2012
		(In millions)	
Operating revenues	$ 1,119.5	$ 1,039.8	$ 938.6
Operating expenses:			
Operation and maintenance	990.7	910.7	831.9
Depreciation, depletion and amortization	12.9	11.9	11.1
Taxes, other than income	33.6	32.0	29.1
	1,037.2	954.6	872.1
Operating income	82.3	85.2	66.5
Earnings	$ 54.5	$ 52.2	$ 38.4

2014 compared to 2013 Construction services earnings increased $2.3 million (4 percent) due to favorable income tax changes, which includes $3.9 million related to the resolution of certain income tax matters and higher income tax benefits; and higher margins, including higher electrical supply sales and margins, higher margins in the Central region and higher workloads and margins in the Western region, partially offset by lower equipment sales revenues. These increases were partially offset by higher selling, general and administrative expense of $3.2 million (after tax), including higher payroll and benefit-related costs.

2013 compared to 2012 Construction services earnings increased $13.8 million (36 percent) compared to the prior year primarily due to higher workloads and margins in the Western and Central regions, as well as higher equipment sales and rental revenue and margins. This increase was partially offset by higher general and administrative expense of $3.3 million (after tax), including higher payroll-related costs.

Other

Years ended December 31,	2014	2013	2012
		(In millions)	
Operating revenues	$ 9.4	$ 9.6	$ 10.4
Operating expenses:			
Operation and maintenance	1.3	.8	3.3
Depreciation, depletion and amortization	2.2	2.1	2.0
Taxes, other than income	.2	.1	.2
	3.7	3.0	5.5
Operating income	5.7	6.6	4.9
Income from continuing operations	7.5	5.1	4.8
Income (loss) from discontinued operations, net of tax	3.1	(.3)	13.6
Earnings	$ 10.6	$ 4.8	$ 18.4

2014 compared to 2013 Other earnings increased $5.8 million compared to the prior year primarily due to favorable income tax changes at both continuing and discontinued operations, including the resolution of certain tax matters and higher income tax benefits.

2013 compared to 2012 Other earnings decreased $13.6 million compared to the prior year primarily due to a loss from discontinued operations of $300,000 (after tax) in 2013, compared to income from discontinued operations of $13.6 million (after tax) in 2012, primarily due to the absence in 2013 of a net benefit in 2012 related to the reversal of an arbitration charge for a guarantee of a construction contract at the domestic power production business, which was sold in 2007, as discussed in Item 8 - Note 3.

Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's elimination of intersegment transactions. The amounts relating to these items are as follows:

Years ended December 31,	**2014**	2013	2012
		(In millions)	
Intersegment transactions:			
Operating revenues	**$ 187.0**	$ 146.4	$ 124.4
Purchased natural gas sold	**92.0**	87.2	82.7
Operation and maintenance	**85.1**	52.1	41.7
Depreciation, depletion and amortization	**.8**	—	—
Earnings on common stock	**5.7**	4.3	—

For more information on intersegment eliminations, see Item 8 - Note 15.

Prospective Information

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

MDU Resources Group, Inc.

- The Company's long-term compound annual growth goals on earnings per share from operations are in the range of 7 to 10 percent.
- The Company continually seeks opportunities to expand through organic growth opportunities and strategic acquisitions.
- The Company focuses on creating value through vertical integration between its business units.

Electric and natural gas distribution

- Rate base growth is projected to be approximately 11 percent compounded annually over the next five years, including plans for an approximate $1.8 billion gross capital investment program with $478 million planned for 2015. Although a prolonged period of lower commodity prices may slow Bakken-area growth in the future, the Company continues to see strong current growth.
- Regulatory actions
  - On July 10, 2014, the NDPSC approved recovery of $8.6 million annually effective July 15, 2014, to reflect actual costs incurred through February 2014 and projected costs through June 2015 for an environmental cost recovery rider related to costs resulting from the retrofit required to be installed at the Big Stone Station. The Company's share of the cost for the installation is approximately $90 million and is expected to be complete in 2015. The NDPSC had earlier approved advance determination of prudence for recovery of costs on the system.
  - On August 11, 2014, October 3, 2014 and February 6, 2015, the Company filed applications with the MTPSC, WYPSC and NDPSC, respectively, for natural gas rate increases, as discussed in Item 8 - Note 18.
  - On November 14, 2014, the Company filed an application with the NDPSC for approval to implement the rate adjustment associated with the electric generation resource recovery rider, as discussed in Item 8 - Note 18.
  - On December 22, 2014, the Company filed for advanced determination of prudence with the NDPSC on the Thunder Spirit Wind project, as discussed in Item 8 - Note 18. The Company recently signed an agreement to purchase the project, which includes 43 wind turbines totaling 107.5 MW of electric generation at a cost of approximately $200 million with approximately $55 million already funded in 2014. The project is being developed by ALLETE Clean Energy with an expected completion in December 2015.

  - The Company has a planned natural gas rate case filing in early 2015 for Oregon. The Company expects to file electric rate cases in 2015 in Montana and South Dakota and a natural gas case in Washington.
- Investments are being made in 2015 totaling approximately $60 million to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is higher than the national average. This reflects a slightly lower capital expenditure level compared to 2014 anticipating a tempering of economic activity due to recent lower oil prices.
- The Company is engaged in a 30-mile, approximately $60 million natural gas line project into the Hanford Nuclear Site in Washington.
- The Company, along with a partner, expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles. The Company's share of the cost is estimated at approximately $170 million. The project is a MISO multi-value project. A route application was filed in August 2013 with the state of South Dakota and in October 2013 with the state of North Dakota. A route permit was approved July 10, 2014, in North Dakota and August 13, 2014, in South Dakota. The South Dakota route permit was appealed and a district court ruled in favor of the project. The district court decision has been appealed to the South Dakota Supreme Court. The Company continues to expect the project to be complete in 2019.
- The Company is pursuing additional generation projects to meet projected capacity requirements, including 19 MW of natural gas generation at the Lewis & Clark Station slated for this year.
- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with company- and customer-owned pipeline facilities designed to serve existing facilities served by fuel oil or propane, and to serve new customers.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest and Idaho.

Pipeline and energy services

- The Company, in conjunction with Calumet formed Dakota Prairie Refining to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 with a projected in-service date in the second quarter 2015. The Dakota Prairie Refinery will process Bakken crude into diesel, which will be marketed within the Bakken region. Other by-products, naphtha and atmospheric tower bottoms, are expected to be railed to other areas. The total project cost estimate is more than $400 million. EBITDA for the first full year of operation is projected to be in the range of $60 million to $80 million, to be shared equally with Calumet.
- The Company is evaluating the construction of a second 20,000-barrel-per-day topping plant to be located near Minot, North Dakota in the Bakken region. It is anticipated the economic evaluation of this project will continue through much of 2015.
- The Company continues work on acquiring right-of-way and easements as well as filing for applicable permits for its planned Wind Ridge Pipeline project, a 95-mile natural gas pipeline designed to deliver approximately 90 MMcf per day to an announced fertilizer plant near Spiritwood, North Dakota. The project cost is estimated to be approximately $120 million with an in-service date in 2017. There is an opportunity to expand this pipeline's capacity to serve other customers in eastern North Dakota.
- The Company has entered into an agreement with an anchor shipper to construct a pipeline to connect the Demicks Lake gas processing plant in northwestern North Dakota to deliver natural gas into a new interconnect with the Northern Border Pipeline. The Company will be holding an open season to gauge additional interest in the project. Project costs are estimated in the $50 million to $60 million range.
- The Company continues to pursue new growth opportunities and expansion of existing facilities and services offered to customers. The Company expects energy development to continue to grow long term within its geographic region, most notably in the Bakken area, where the Company owns an extensive natural gas pipeline system. The company plans to invest $1.1 billion of capital related to ongoing energy and industrial development over the next five years.

Exploration and production

- The Company intends to market its exploration and production company in the future and although an actual sale date is unknown, for forecasting purposes the Company is assuming a sale transaction after 2015.
- During 2015, the Company plans to continue to focus on maximizing the value of Fidelity to ultimately market it for sale including focusing on lowering its cost structure beyond the 25 percent general and administrative cost reduction already in place.
- The Company expects to spend approximately $111 million in gross capital expenditures in 2015 operating within projected cash flows. Plans are to minimize investments in the first half of the year to allow service costs to better align with the lower commodity price environment. The Company currently has no rigs drilling on its operated properties and anticipates commencing drilling in the second half of the year.
- Key activities for 2015 include:
  - Commissioning and start-up of the gas gathering and processing facilities in the Paradox in addition to new wells and existing well recompletes.
  - Completion of a backlog of wells in the non-operated Powder River Basin.
  - Drilling and completing additional horizontal wells in East Texas.

- Completion of 2014 activity carryover in the Bakken.
- Well updates:
  - The Cane Creek Unit 28-3 well (100 percent working interest) was completed in mid-December 2014 and was slowly ramped up to about 600 BOPD utilizing an 11/64ths-inch choke and a flowing tubing pressure of approximately 2,600 pounds per square inch. The production rate has been held relatively constant for the last three weeks.
  - The Company completed the Poovey Mark Poovey 1H well (100 percent working interest), its first East Texas Cotton Valley horizontal well. Initial production rate for the well peaked at 11 MMcf per day declining to recent rates of 9 MMcf per day.
- Annual oil production is expected to decline approximately 22 percent in 2015 primarily due to 2014 divestments in the Bakken and limited oil related investments in 2015. Annual natural gas and natural gas liquids volumes are estimated to decrease 10 percent and 20 percent respectively in 2015 primarily the result of 2014 asset divestments in South Texas. The December 2015 oil production rate is estimated to decrease 14 percent compared to December 2014, while natural gas and NGL rates are estimated to increase 4 percent and 23 percent, respectively. The Company is assuming average NYMEX index prices for 2015 of $50 per Bbl of crude oil, $3.00 per Mcf of natural gas and $24 per Bbl of NGL.
- Derivatives in place as of February 2, 2015, include:
  - For January through March 2015, 3,000 BOPD at a weighted average price of $98.00.
  - For January through March 2015, 15,000 MMBtu of natural gas per day at a weighted average price of $4.39.
  - For 2015, 10,000 MMBtu of natural gas per day at a weighted average price of $4.28.

Construction materials and contracting

- Approximate work backlog as of December 31, 2014, was $438 million, compared to $456 million a year ago. Private work represents 11 percent of construction backlog and public work represents 89 percent of backlog. The backlog includes a variety of projects such as highway grading, paving and underground projects, airports, bridge work and subdivisions.
- Projected revenues included in the Company's 2015 earnings guidance are in the range of $1.7 billion to $1.9 billion.
- The Company anticipates margins in 2015 to be in line with 2014 margins.
- The Company continues to pursue opportunities for expansion in energy projects such as petrochemical, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the country's fifth-largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Approximate work backlog as of December 31, 2014, was $305 million, compared to $459 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including petrochemical work.
- Projected revenues included in the Company's 2015 earnings guidance are in the range of $1.1 billion to $1.3 billion.
- The Company anticipates margins in 2015 to be in line with 2014 margins.
- The Company continues to pursue opportunities for expansion in energy projects such as petrochemical, transmission, substations, utility services and solar. Initiatives are aimed at capturing additional market share and expanding into new markets.

New Accounting Standards

For information regarding new accounting standards, see Item 8 - Note 1, which is incorporated herein by reference.

Critical Accounting Policies Involving Significant Estimates

The Company has prepared its financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 - Note 1.

Estimates are used for items such as impairment testing of long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; oil, NGL and natural gas reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. The Company's critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies.

As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. The following critical accounting policies involve significant judgments and estimates.

Oil and natural gas properties

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The extent, quality and reliability of this data can vary. Other factors used in the reserve estimates are prices, market differentials, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Changes in proved reserve quantities impact the Company's depreciation, depletion and amortization expense since the Company uses the units-of-production method to amortize its oil and natural gas properties. The proved reserves are also used as the basis for the disclosures in Item 8 - Supplementary Financial Information and are the underlying basis of the "ceiling test" for the Company's oil and natural gas properties.

The Company uses the full-cost method of accounting for its exploration and production activities. Under this method, capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash flows associated with asset retirement obligations that have been accrued on the balance sheet. Judgments and assumptions are made when estimating and valuing proved reserves. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter in 2014 were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
December 31, 2014	$ 94.99	$ 4.34	$ 7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47
March 31, 2014	98.46	3.99	7.33

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
January 2015	$ 53.27	$ 3.00	$ 3.06
February 2015	48.24	2.68	2.78

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and at least annually for goodwill.

Goodwill The Company performs its goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which the Company's reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Item 8 - Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2014, 2013, and 2012, there were no significant impairment losses recorded. At December 31, 2014, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2014. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Long-Lived Assets Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the asset could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known when the estimates are made.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include costs on construction contracts under the percentage-of-completion method.

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor, materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known. If a loss is anticipated on a contract, the loss is immediately recognized.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job. There were no material changes in contract estimates at the individual contract level in 2014.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases, actuarially determined mortality data, and healthcare cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the healthcare cost trend rates are determined by historical and future trends. The Company estimates that a 50 basis point decrease in the discount rate or in the expected return on plan assets would each increase expense by less than $1.5 million (after tax) for the year ended December 31, 2014.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and healthcare cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For more information on the assumptions used in determining plan costs, see Item 8 - Note 16.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect the income tax expense by less than $4.2 million for the year ended December 31, 2014.

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

The Company believes its estimates surrounding income taxes are reasonable based on the information that is known when the estimates are made.

Liquidity and Capital Commitments

At December 31, 2014, the Company had cash and cash equivalents of $81.9 million and available capacity of $677.3 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital.

Cash flows provided by operating activities in 2014 decreased $126.4 million from 2013. The decrease was primarily due to higher working capital requirements of $131.9 million, primarily at the exploration and production and construction services businesses.

Cash flows provided by operating activities in 2013 increased $157.5 million from 2012. The increase was primarily due to lower working capital requirements of $132.9 million, primarily at the exploration and production and construction materials and contracting businesses and higher income from continuing operations, largely at the exploration and production business.

Investing activities Cash flows used in investing activities in 2014 increased $121.5 million from 2013 primarily due to higher acquisition-related capital expenditures, largely at the exploration and production business, as well as higher capital expenditures, primarily at the pipeline and energy services business. Partially offsetting the increase in cash flows used in investing activities was higher proceeds from the sale of properties, largely at the exploration and production business.

Cash flows used in investing activities in 2013 decreased $105.3 million from 2012 primarily due to higher proceeds from the sale of properties, largely at the exploration and production business, as well as lower acquisition-related capital expenditures, primarily at the pipeline and energy services business. Partially offsetting the decrease in cash flows used in investing activities was higher ongoing capital expenditures of $36.5 million, largely related to Dakota Prairie Refinery at the pipeline and energy services business and electric generation projects at the electric business, partially offset by lower capital expenditures at the exploration and production business.

Financing activities Cash flows provided by financing activities in 2014 increased $288.3 million from 2013, primarily due to the issuance of $135.5 million of common stock, as well as higher issuance of long-term debt of $98.2 million, a higher cash contribution of $59.9 million related to the noncontrolling interest and lower repayment of long-term debt of $54.9 million. Partially offsetting this increase were higher dividends paid in 2014 compared to 2013 due to the acceleration of the first quarter 2013 quarterly common stock dividend to 2012.

Cash flows provided by financing activities in 2013 decreased $152.8 million from 2012, primarily due to higher repayment of long-term debt of $284.9 million. Partially offsetting the decrease in cash flows provided by financing activities were lower dividends paid of $61.4 million resulting from the Company accelerating the payment date for the quarterly common stock dividend from January 1, 2013 to December 31, 2012; higher issuance of long-term debt of $40.0 million; as well as a cash contribution of $27.0 million related to the noncontrolling interest.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the pension plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. At December 31, 2014, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $121.0 million. Pretax pension expense reflected in the years ended December 31, 2014, 2013 and 2012, was $1.1 million, $3.0 million and $204,000, respectively. The Company's pension expense is currently projected to be approximately $3.0 million to $4.0 million in 2015. Funding for the pension plans is actuarially determined. The minimum required contributions for 2014, 2013 and 2012 were approximately $10.8 million, $13.2 million and $16.1 million, respectively. For more information on the Company's pension plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures for 2012 through 2014 and as anticipated for 2015 through 2017 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2012	2013	**2014**	2015	2016	2017
			(In millions)			
Capital expenditures:						
Electric	$ 112	$ 169	**$ 185**	$ 319	$ 172	$ 177
Natural gas distribution	130	101	**121**	159	191	158
Pipeline and energy services**	134	127	**177**	111	423	336
Exploration and production***	554	391	**601**	111	—	—
Construction materials and contracting	45	35	**38**	49	206	123
Construction services	15	15	**27**	24	82	72
Other	1	2	**2**	5	4	2
Net proceeds from sale or disposition of property and other	(57)	(112)	**(307)**	(86)	(4)	(7)
Net capital expenditures	934	728	**844**	692	1,074	861
Retirement of long-term debt	139	424	**369**	269	294	51
	$ 1,073	$ 1,152	**$ 1,213**	$ 961	$ 1,368	$ 912

* The Company continues 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 above estimates.

** Amounts include the Company's share of capital expenditures related to Dakota Prairie Refinery, as discussed in Prospective Information and Item 8 - Note 19.

*** Future exploration and production capital expenditures are dependent upon the timing of marketing and sale. Sale proceeds for the business are excluded from capital expenditure projections.

Capital expenditures for 2014, 2013 and 2012 in the preceding table include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. These net transactions were $(61.2) million in 2014, $(56.8) million in 2013 and $33.7 million in 2012.

The 2014 capital expenditures, including those for the retirement of long-term debt, were met from internal sources and the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2015 through 2017 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline, gathering and other midstream projects
- Further development of existing properties at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity and purchase agreement of electric wind generation
- Environmental upgrades
- Potential acquisitions at the construction materials and contracting and construction services segments
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- Construction of a second 20,000-barrel-per-day topping plant at the pipeline and energy services segment, currently under evaluation
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2015 through 2017 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; through the issuance of long-term debt and the Company's equity securities; and asset sales.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2014. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 9.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2014:

Company	Facility	Facility Limit	Amount Outstanding	Letters of Credit	Expiration Date
			(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 175.0	$ 77.5 (b)	$ —	5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ —	$ 2.2 (d)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (e)	$ 21.0	$ —	7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$ 650.0	$ 211.0 (b)	$ —	5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement	$ 50.0 (g)	$ —	$ 1.0 (d)	12/1/15

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option the Company on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million.
(d) An outstanding letter of credit reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $800.0 million). There were no amounts outstanding under the credit agreement.
(g) Certain provisions allow for increased borrowings up to a maximum of $75.0 million.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

MDU Resources Group, Inc. On May 8, 2014, the Company amended the revolving credit agreement to increase the borrowing limit to $175.0 million and extend the termination date to May 8, 2019. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

The Company's coverage of fixed charges including preferred stock dividends was 4.5 times and 4.8 times for the 12 months ended December 31, 2014 and 2013.

Total equity as a percent of total capitalization was 61 percent and 60 percent at December 31, 2014 and 2013. This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Sales of such common stock may not be made after February 28, 2016. Proceeds from the shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. Under the Equity Distribution Agreement, the Company issued 3.9 million shares of stock during 2014, receiving net proceeds of $130.1 million. Since inception of the Equity Distribution Agreement, the Company has issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through December 31, 2014.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities. The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

Centennial Energy Holdings, Inc. On May 8, 2014, Centennial entered into an amended and restated revolving credit agreement which increased the borrowing limit to $650.0 million and extended the termination date to May 8, 2019. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

WBI Energy Transmission, Inc. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2014, which reduced capacity under this uncommitted private shelf agreement.

Dakota Prairie Refining, LLC On December 1, 2014, Dakota Prairie Refining entered into a $50.0 million revolving credit agreement with an expiration date of December 1, 2015. This credit agreement is used to meet the operational needs of Dakota Prairie Refining.

Off balance sheet arrangements

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines. For more information, see Item 8 - Note 4.

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see Item 8 - Notes 9 and 19. At December 31, 2014, the Company's commitments under these obligations were as follows:

	2015	2016	2017	2018	2019	Thereafter	Total
				(In millions)			
Long-term debt	$ 269.4	$ 293.8	$ 51.0	$ 148.2	$ 345.7	$ 986.6	$ 2,094.7
Estimated interest payments*	92.3	71.1	61.9	60.1	51.6	472.4	809.4
Operating leases	48.1	43.5	34.3	28.1	19.7	78.7	252.4
Purchase commitments	694.7	304.6	161.0	91.0	86.4	910.6	2,248.3
	$ 1,104.5	$ 713.0	$ 308.2	$ 327.4	$ 503.4	$ 2,448.3	$ 5,404.8

* Estimated interest payments are calculated based on the applicable rates and payment dates.

At December 31, 2014, the Company had total liabilities of $92.8 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $13.7 million at December 31, 2014, and was included in other accrued liabilities on the Consolidated Balance Sheet. The remainder, which constitutes the long-term portion of asset retirement obligations, was included in other liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 - Note 10.

Not reflected in the previous table are $137,000 in uncertain tax positions. For more information, see Item 8 - Note 14.

The Company's minimum funding requirements for its defined benefit pension plans for 2015, which are not reflected in the previous table, are $3.9 million. For information on potential contributions above the minimum funding requirements, see Item 8 - Note 16.

The Company's MEPP contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its MEPPs as a result of their funded status. For more information, see Item 1A - Risk Factors and Item 8 - Note 16.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2014, 2013 or 2012.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company is exposed to the impact of market fluctuations associated with commodity prices and interest rates. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

For more information on derivatives and the Company's derivative policies and procedures, see Item 8 - Consolidated Statements of Comprehensive Income and Notes 1 and 7.

Commodity price risk

Fidelity utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on forecasted sales of oil and natural gas production.

The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2014. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional volume and fair value in thousands)		
	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2015	$ 98.00	270	$ 11,895
Natural gas swap agreements maturing in 2015	$ 4.31	5,000	$ 6,440

The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2013. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional volume and fair value in thousands)		
	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2014	$ 94.74	2,911	$ (4,771)
Natural gas swap agreements maturing in 2014	$ 4.10	14,600	$ (1,265)
Natural gas swap agreement maturing in 2015	$ 4.28	3,650	$ 503

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term financing. The Company from time to time uses interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk.

At December 31, 2014 and 2013, the Company had no outstanding interest rate hedges.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2014.

	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 266.4	$ 288.6	$ 43.5	$ 108.5	$ 51.2	$ 955.1	$ 1,713.3	$ 1,859.8
Weighted average interest rate	5.7%	6.4%	6.3%	6.1%	4.3%	5.1%	5.5%	—
Variable rate	$ 3.0	$ 5.2	$ 7.5	$ 39.7	$ 294.5	$ 31.5	$ 381.4	$ 379.6
Weighted average interest rate	1.2%	1.8%	2.1%	2.6%	.4%	2.5%	.9%	—

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of MDU Resources Group, Inc. is 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. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*.

Based on our evaluation under the framework in *Internal Control-Integrated Framework (2013)*, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2014, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

David L. Goodin
President and Chief Executive Officer

Doran N. Schwartz
Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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 consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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 MDU Resources Group, Inc. 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 schedules, 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 20, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 20, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the internal control over financial reporting of MDU Resources Group, Inc. 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. 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.

In our opinion, the Company maintained, in all material respects, 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 schedules as of and for the year ended December 31, 2014 of the Company and our report dated February 20, 2015 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 20, 2015

Consolidated Statements of Income

Years ended December 31,	2014	2013	2012
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$ 1,366,356	$ 1,264,574	$ 1,131,626
Exploration and production, construction materials and contracting, construction services and other	3,304,202	3,197,830	2,943,805
Total operating revenues	4,670,558	4,462,404	4,075,431
Operating expenses:			
Fuel and purchased power	89,312	83,528	72,380
Purchased natural gas sold	570,041	505,065	425,220
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	303,822	269,825	254,194
Exploration and production, construction materials and contracting, construction services and other	2,625,228	2,535,872	2,377,285
Depreciation, depletion and amortization	401,368	386,856	359,205
Taxes, other than income	192,562	188,359	176,140
Write-downs of oil and natural gas properties (Note 1)	—	—	391,800
Total operating expenses	4,182,333	3,969,505	4,056,224
Operating income	488,225	492,899	19,207
Earnings (loss) from equity method investments	(41)	(132)	5,383
Other income	9,962	6,768	6,642
Interest expense	87,016	83,917	76,699
Income (loss) before income taxes	411,130	415,618	(45,467)
Income taxes	119,969	136,736	(31,146)
Income (loss) from continuing operations	291,161	278,882	(14,321)
Income (loss) from discontinued operations, net of tax (Note 3)	3,177	(312)	13,567
Net income (loss)	294,338	278,570	(754)
Net loss attributable to noncontrolling interest	(3,895)	(363)	—
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$ 297,548	$ 278,248	$ (1,439)
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	$ 1.53	$ 1.47	$ (.08)
Discontinued operations, net of tax	.02	—	.07
Earnings (loss) per common share - basic	$ 1.55	$ 1.47	$ (.01)
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	$ 1.53	$ 1.47	$ (.08)
Discontinued operations, net of tax	.02	—	.07
Earnings (loss) per common share - diluted	$ 1.55	$ 1.47	$ (.01)
Weighted average common shares outstanding - basic	192,507	188,855	188,826
Weighted average common shares outstanding - diluted	192,587	189,693	188,826

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2014	2013	2012
		(In thousands)	
Net income (loss)	$ **294,338**	$ 278,570	$ (754)
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $0, $(3,116) and $4,829 in 2014, 2013 and 2012, respectively	**—**	(5,594)	8,497
Reclassification adjustment for (gain) loss on derivative instruments included in net income, net of tax of $413, $(2,548) and $(5,141) in 2014, 2013 and 2012, respectively	**694**	(4,189)	(8,754)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**694**	(9,783)	(257)
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $(7,665), $11,818 and $(2,060) in 2014, 2013 and 2012, respectively	**(12,409)**	18,539	(3,106)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $492, $1,276 and $1,379 in 2014, 2013 and 2012, respectively	**796**	2,001	2,079
Reclassification of postretirement liability adjustment to regulatory asset, net of tax of $4,509, $0 and $0 in 2014, 2013 and 2012, respectively	**7,202**	—	—
Postretirement liability adjustment	**(4,411)**	20,540	(1,027)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(99), $(177) and $(296) in 2014, 2013 and 2012, respectively	**(162)**	(299)	(476)
Reclassification adjustment for (gain) loss on foreign currency translation adjustment included in net income, net of tax of $0, $70 and $2 in 2014, 2013 and 2012, respectively	**—**	143	3
Foreign currency translation adjustment	**(162)**	(156)	(473)
Net unrealized gain (loss) on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(83), $(105) and $(52) in 2014, 2013 and 2012, respectively	**(154)**	(194)	(97)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $73, $59 and $72 in 2014, 2013 and 2012, respectively	**135**	109	134
Net unrealized gain (loss) on available-for-sale investments	**(19)**	(85)	37
Other comprehensive income (loss)	**(3,898)**	10,516	(1,720)
Comprehensive income (loss)	**290,440**	289,086	(2,474)
Comprehensive loss attributable to noncontrolling interest	**(3,895)**	(363)	—
Comprehensive income (loss) attributable to common stockholders	$ **294,335**	$ 289,449	$ (2,474)

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

Consolidated Balance Sheets

December 31,	2014	2013
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 81,855	$ 45,225
Receivables, net	693,318	713,067
Inventories	300,811	282,391
Deferred income taxes	23,806	25,048
Commodity derivative instruments	18,335	1,447
Prepayments and other current assets	76,848	49,510
Total current assets	1,194,973	1,116,688
Investments	117,920	112,939
Property, plant and equipment (Note 1)	9,693,171	8,803,866
Less accumulated depreciation, depletion and amortization	4,166,407	3,872,487
Net property, plant and equipment	5,526,764	4,931,379
Deferred charges and other assets:		
Goodwill (Note 5)	635,204	636,039
Other intangible assets, net (Note 5)	9,840	13,099
Other	325,277	251,188
Total deferred charges and other assets	970,321	900,326
Total assets	$ 7,809,978	$ 7,061,332
Liabilities and Equity		
Current liabilities:		
Short-term borrowings (Note 9)	$ —	$ 11,500
Long-term debt due within one year	269,449	12,277
Accounts payable	382,671	404,961
Taxes payable	45,631	74,175
Dividends payable	35,607	33,737
Accrued compensation	62,775	69,661
Commodity derivative instruments	—	7,483
Other accrued liabilities	172,561	171,106
Total current liabilities	968,694	784,900
Long-term debt (Note 9)	1,825,278	1,842,286
Deferred credits and other liabilities:		
Deferred income taxes	952,413	859,306
Other liabilities	813,809	718,938
Total deferred credits and other liabilities	1,766,222	1,578,244
Commitments and contingencies (Notes 16, 18 and 19)		
Equity:		
Preferred stocks (Note 11)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 12) Authorized - 500,000,000 shares, $1.00 par value Issued - 194,754,812 shares in 2014 and 189,868,780 shares in 2013	194,755	189,869
Other paid-in capital	1,207,188	1,056,996
Retained earnings	1,762,827	1,603,130
Accumulated other comprehensive loss	(42,103)	(38,205)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	3,119,041	2,808,164
Total stockholders' equity	3,134,041	2,823,164
Noncontrolling interest	115,743	32,738
Total equity	3,249,784	2,855,902
Total liabilities and equity	$ 7,809,978	$ 7,061,332

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

Consolidated Statements of Equity

Years ended December 31, 2014, 2013 and 2012

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock Shares	Treasury Stock Amount	Noncontrolling Interest	Total
					(In thousands, except shares)						
Balance at December 31, 2011	150,000	$15,000	189,332,485	$189,332	$1,035,739	$1,586,123	$(47,001)	(538,921)	$(3,626)	$ —	$2,775,567
Net loss	—	—	—	—	—	(754)	—	—	—	—	(754)
Other comprehensive loss	—	—	—	—	—	—	(1,720)	—	—	—	(1,720)
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(127,538)	—	—	—	—	(127,538)
Stock-based compensation	—	—	25,743	26	5,094	—	—	—	—	—	5,120
Net tax deficit on stock-based compensation	—	—	—	—	(1,958)	—	—	—	—	—	(1,958)
Issuance of common stock	—	—	11,222	11	205	—	—	—	—	—	216
Balance at December 31, 2012	150,000	15,000	189,369,450	189,369	1,039,080	1,457,146	(48,721)	(538,921)	(3,626)	—	2,648,248
Net income (loss)	—	—	—	—	—	278,933	—	—	—	(363)	278,570
Other comprehensive income	—	—	—	—	—	—	10,516	—	—	—	10,516
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(132,264)	—	—	—	—	(132,264)
Stock-based compensation	—	—	—	—	5,281	—	—	—	—	—	5,281
Net tax deficit on stock-based compensation	—	—	—	—	(1,419)	—	—	—	—	—	(1,419)
Issuance of common stock	—	—	499,330	500	14,054	—	—	—	—	—	14,554
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	33,101	33,101
Balance at December 31, 2013	150,000	15,000	189,868,780	189,869	1,056,996	1,603,130	(38,205)	(538,921)	(3,626)	32,738	2,855,902
Net income (loss)	—	—	—	—	—	298,233	—	—	—	(3,895)	294,338
Other comprehensive loss	—	—	—	—	—	—	(3,898)	—	—	—	(3,898)
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(137,851)	—	—	—	—	(137,851)
Stock-based compensation	—	—	—	—	6,191	—	—	—	—	—	6,191
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	326,122	326	(5,890)	—	—	—	—	—	(5,564)
Excess tax benefit on stock-based compensation	—	—	—	—	4,729	—	—	—	—	—	4,729
Issuance of common stock	—	—	4,559,910	4,560	145,162	—	—	—	—	—	149,722
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	86,900	86,900
Balance at December 31, 2014	**150,000**	**$ 15,000**	**194,754,812**	**$ 194,755**	**$ 1,207,188**	**$ 1,762,827**	**$ (42,103)**	**(538,921)**	**$ (3,626)**	**$115,743**	**$ 3,249,784**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2014	2013	2012
		(In thousands)	
Operating activities:			
Net income (loss)	$ 294,338	$ 278,570	$ (754)
Income (loss) from discontinued operations, net of tax	3,177	(312)	13,567
Income (loss) from continuing operations	291,161	278,882	(14,321)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	401,368	386,856	359,205
Earnings (loss), net of distributions, from equity method investments	550	2,281	(618)
Deferred income taxes	87,015	86,778	(7,503)
Unrealized (gain) loss on commodity derivatives	(23,400)	6,267	624
Write-downs of oil and natural gas properties (Note 1)	—	—	391,800
Excess tax benefit on stock-based compensation	(4,729)	—	(26)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	6,166	(40,669)	(13,416)
Inventories	(18,738)	30,452	(42,334)
Other current assets	(25,997)	(9,474)	297
Accounts payable	(45,065)	15,084	6,352
Other current liabilities	(23,515)	29,392	(59,001)
Other noncurrent changes	(29,193)	(43,937)	(33,639)
Net cash provided by continuing operations	615,623	741,912	587,420
Net cash provided by (used in) discontinued operations	159	281	(2,680)
Net cash provided by operating activities	615,782	742,193	584,740
Investing activities:			
Capital expenditures	(972,102)	(909,400)	(872,920)
Acquisitions, net of cash acquired	(209,213)	—	(67,261)
Net proceeds from sale or disposition of property and other	276,415	124,541	40,110
Investments	709	302	9,725
Proceeds from sale of equity method investments	—	1,896	2,394
Net cash used in continuing operations	(904,191)	(782,661)	(887,952)
Net cash provided by discontinued operations	—	—	—
Net cash used in investing activities	(904,191)	(782,661)	(887,952)
Financing activities:			
Issuance of short-term borrowings	—	9,500	20,100
Repayment of short-term borrowings	(11,500)	—	—
Issuance of long-term debt	606,084	507,924	467,957
Repayment of long-term debt	(368,803)	(423,707)	(138,775)
Proceeds from issuance of common stock	150,060	14,554	88
Dividends paid	(136,712)	(98,405)	(159,768)
Excess tax benefit on stock-based compensation	4,729	—	26
Tax withholding on stock-based compensation	(5,564)	—	—
Contribution from noncontrolling interest	86,900	27,000	—
Net cash provided by continuing operations	325,194	36,866	189,628
Net cash provided by discontinued operations	—	—	—
Net cash provided by financing activities	325,194	36,866	189,628
Effect of exchange rate changes on cash and cash equivalents	(155)	(215)	(146)
Increase (decrease) in cash and cash equivalents	36,630	(3,817)	(113,730)
Cash and cash equivalents - beginning of year	45,225	49,042	162,772
Cash and cash equivalents - end of year	$ 81,855	$ 45,225	$ 49,042

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

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The abbreviations and acronyms used throughout are defined following the Notes to Consolidated Financial Statements. The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2014, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $30.9 million and $36.4 million at December 31, 2014 and 2013, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2014 and 2013, was $9.5 million and $10.1 million, respectively.

Inventories and natural gas in storage

Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

		2014		2013
		(In thousands)		
Aggregates held for resale	$	**108,161**	$	101,568
Materials and supplies		**65,683**		69,808
Asphalt oil		**42,135**		38,099
Merchandise for resale		**24,420**		21,720
Natural gas in storage (current)		**19,302**		16,417
Other		**41,110**		34,779
Total	$	**300,811**	$	282,391

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $49.3 million and $48.3 million at December 31, 2014 and 2013, respectively.

Investments

The Company's investments include its equity method and cost method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive income (loss). For more information, see Notes 8 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in Oil and natural gas properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, at the exploration and production segment only on costs that have been excluded from the full cost amortization pool and on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized for the years ended December 31 were as follows:

		2014		2013		2012
				(In thousands)		
Interest capitalized	$	**8,586**	$	6,033	$	8,659
AFUDC - borrowed	$	**3,022**	$	2,767	$	2,483
AFUDC - equity	$	**5,803**	$	3,322	$	4,530

Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and exploration and production properties, which are amortized on the units-of-production method based on total proved reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

Property, plant and equipment at December 31 was as follows:

	2014	2013	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 627,952	$ 570,394	42
Distribution	343,692	308,202	39
Transmission	229,997	196,824	48
Construction in progress	150,445	141,365	-
Other	105,015	99,037	15
Natural gas distribution:			
Distribution	1,481,390	1,384,587	40
Construction in progress	59,310	46,763	-
Other	364,059	345,551	27
Pipeline and energy services:			
Transmission	449,276	418,594	53
Gathering	39,595	39,597	20
Storage	43,994	42,939	60
Construction in progress	5,386	6,937	-
Other	39,910	39,504	33
Nonregulated:			
Pipeline and energy services:			
Midstream	227,598	213,063	16
Construction in progress	314,304	188,641	-
Other	100,170	12,897	18
Exploration and production:			
Oil and natural gas properties	3,337,177	3,017,879	*
Other	65,702	42,969	8
Construction materials and contracting:			
Land	125,372	125,551	-
Buildings and improvements	70,566	70,000	19
Machinery, vehicles and equipment	921,564	906,774	12
Construction in progress	8,709	13,315	-
Aggregate reserves	403,731	394,715	**
Construction services:			
Land	5,265	4,821	-
Buildings and improvements	17,936	16,628	20
Machinery, vehicles and equipment	112,973	105,991	6
Other	8,221	7,508	4
Other:			
Land	2,837	2,837	-
Other	48,100	47,160	23
Eliminations	(17,075)	(7,177)	
Less accumulated depreciation, depletion and amortization	4,166,407	3,872,487	
Net property, plant and equipment	$ 5,526,764	$ 4,931,379	

*Amortized on the units-of-production method based on total proved reserves at a BOE average rate of $21.17, $17.41 and $15.28 for the years ended December 31, 2014, 2013 and 2012, respectively. Includes oil and natural gas properties accounted for under the full-cost method, of which $132.1 million and $124.9 million were excluded from amortization at December 31, 2014 and 2013, respectively.

** Depleted on the units-of-production method.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2013 and 2012, the Company recognized impairments of $9.0 million (after tax) and $1.7 million (after tax), respectively, which are recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairments are related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a significant decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to fair value that was determined using the income approach. For more information on this nonrecurring fair value measurement, see Note 8.

No significant impairment losses were recorded in 2014. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2014, 2013 and 2012, there were no significant impairment losses recorded. At December 31, 2014, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2014. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Oil and natural gas properties

The Company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units-of-production method based on total 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.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash outflows associated with asset retirement obligations that have been accrued on the balance sheet. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

SEC Defined Prices for each quarter in 2014 were as follows:

SEC Defined Prices for the 12 months ended		NYMEX Oil Price (per Bbl)		Henry Hub Gas Price (per MMBtu)		Ventura Gas Price (per MMBtu)
December 31, 2014	$	94.99	$	4.34	$	7.71
September 30, 2014		99.08		4.24		7.60
June 30, 2014		100.27		4.10		7.47
March 31, 2014		98.46		3.99		7.33

For purposes of comparison, first-of-the-month prices were as follows:

		NYMEX Oil Price (per Bbl)		Henry Hub Gas Price (per MMBtu)		Ventura Gas Price (per MMBtu)
January 2015	$	53.27	$	3.00	$	3.06
February 2015		48.24		2.68		2.78

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

At December 31, 2014 and 2013, the Company's full-cost ceiling exceeded the Company's capitalized cost. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

The Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2012 and December 31, 2012. SEC Defined Prices, adjusted for market differentials, are used to calculate the ceiling test. SEC Defined Prices as of September 30, 2012 and December 31, 2012, were $94.97 per Bbl for NYMEX oil and $2.83 per MMBtu for Henry Hub natural gas and $94.71 per Bbl for NYMEX oil and $2.76 per MMBtu for Henry Hub natural gas, respectively. Accordingly, the Company was required to write down its oil and natural gas producing properties. The noncash write-downs amounted to $160.1 million and $231.7 million ($100.9 million and $145.9 million after tax) for the three months ended September 30, 2012 and December 31, 2012, respectively.

The Company hedged a portion of its oil and natural gas production and the effects of the cash flow hedges were used in determining the full-cost ceiling at September 30, 2012 and December 31, 2012. The Company would have recognized additional write-downs of its oil and natural gas properties of $19.5 million ($12.3 million after tax) at September 30, 2012, and $20.8 million ($13.1 million after tax) at December 31, 2012, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

The following table summarizes the Company's oil and natural gas properties not subject to amortization at December 31, 2014, in total and by the year in which such costs were incurred:

				Year Costs Incurred						
		Total		2014		2013		2012		2011 and prior
						(In thousands)				
Acquisition	$	97,795	$	82,233	$	1,528	$	475	$	13,559
Development		14,312		3,361		9,928		484		539
Exploration		18,221		10,961		3,126		3,885		249
Capitalized interest		1,813		1,343		203		67		200
Total costs not subject to amortization	$	132,141	$	97,898	$	14,785	$	4,911	$	14,547

Costs not subject to amortization as of December 31, 2014, consisted primarily of unevaluated leaseholds and development costs in the Powder River Basin and the Paradox Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $99.7 million and $107.4 million at December 31, 2014 and 2013, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized.

Costs and estimated earnings in excess of billings on uncompleted contracts represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts represent billings in excess of revenues recognized and were included in accounts payable. Costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings on uncompleted contracts at December 31, were as follows:

	2014	2013
	(In thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	**$ 58,243**	$ 60,828
Billings in excess of costs and estimated earnings on uncompleted contracts	**$ 47,011**	$ 84,189

Amounts representing balances billed but not paid by customers under retainage provisions in contracts at December 31, were as follows:

	2014	2013
	(In thousands)	
Short-term retainage*	**$ 47,551**	$ 55,906
Long-term retainage**	**1,053**	4,229
Total retainage	**$ 48,604**	$ 60,135

* Expected to be paid within one year or less and included in receivables, net.
** Included in deferred charges and other assets - other.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price and interest rate risk management program to efficiently manage and minimize commodity price and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of oil and natural gas production at Fidelity for a period up to 42 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical oil and natural gas production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the

Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $13.2 million and $16.9 million at December 31, 2014 and 2013, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $19.6 million and $12.1 million at December 31, 2014 and 2013, respectively, which is included in prepayments and other current assets.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, as discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding performance share awards. In 2014 and 2013, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for the year ended December 31, 2012, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for the year ended December 31, 2012, the effect of outstanding performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury. Net income (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculation was as follows:

	2014	2013	2012
		(In thousands)	
Weighted average common shares outstanding - basic	**192,507**	188,855	188,826
Effect of dilutive performance share awards	**80**	838	—
Weighted average common shares outstanding - diluted	**192,587**	189,693	188,826
Shares excluded from the calculation of diluted earnings per share	**—**	—	58

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; oil, NGL and natural gas proved reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

	2014	2013	2012
		(In thousands)	
Interest, net of amount capitalized	**$ 81,351**	$ 81,689	$ 74,378
Income taxes paid, net	**$ 69,087**	$ 24,857	$ 3,277

Noncash investing transactions at December 31 were as follows:

	2014	2013	2012
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 103,327**	$ 67,129	$ 76,205

New accounting standards

Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. This guidance will be effective for the Company on January 1, 2017. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is evaluating the effects the adoption of the new revenue guidance will have on its results of operations, financial position, cash flows and disclosures, as well as its method of adoption.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

The Company's evaluation of whether it qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains (losses) on available-for-sale investments. For more information on derivative instruments, see Note 7.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2014, 2013 and 2012, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2012	$ 6,018	$ (54,347)	$ (511)	$ 119	$ (48,721)
Other comprehensive income (loss) before reclassifications	(5,594)	18,539	(299)	(194)	12,452
Amounts reclassified from accumulated other comprehensive loss	(4,189)	2,001	143	109	(1,936)
Net current-period other comprehensive income (loss)	(9,783)	20,540	(156)	(85)	10,516
Balance at December 31, 2013	(3,765)	(33,807)	(667)	34	(38,205)
Other comprehensive income (loss) before reclassifications	—	(12,409)	(162)	(154)	(12,725)
Amounts reclassified from accumulated other comprehensive loss	694	796	—	135	1,625
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	—	7,202	—	—	7,202
Net current-period other comprehensive income (loss)	694	(4,411)	(162)	(19)	(3,898)
Balance at December 31, 2014	**$ (3,071)**	**$ (38,218)**	**$ (829)**	**$ 15**	**$ (42,103)**

Reclassifications out of accumulated other comprehensive loss for the year ended December 31 were as follows:

	2014	2013	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for gain (loss) on derivative instruments included in net income:			
Commodity derivative instruments	$ (468)	$ 7,803	Operating revenues
Interest rate derivative instruments	(639)	(1,066)	Interest expense
	(1,107)	6,737	
	413	(2,548)	Income taxes
	(694)	4,189	
Amortization of postretirement liability losses included in net periodic benefit cost	(1,288)	(3,277)	(a)
	492	1,276	Income taxes
	(796)	(2,001)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	—	(213)	Earnings (loss) from equity method investments
	—	70	Earnings (loss) from equity method investments
	—	(143)	
Reclassification adjustment for loss on available-for-sale investments included in net income	(208)	(168)	Other income
	73	59	Income taxes
	(135)	(109)	
Total reclassifications	$ (1,625)	$ 1,936	

(a) Included in net periodic benefit cost (credit). For more information, see Note 16.

Note 2 - Acquisitions

On February 10, 2014, the Company entered into agreements to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. The effective date of the acquisition was October 1, 2013, and the closing occurred on March 6, 2014.

The total purchase price, including purchase price adjustments, for acquisitions in 2014 was approximately $209.2 million, including the above acquisition.

In 2012, the Company acquired a 50 percent undivided interest in natural gas and oil midstream assets in western North Dakota. The acquisition includes a natural gas processing plant and a natural gas gathering pipeline system, along with an oil gathering system, an oil storage terminal and an oil pipeline. The total purchase consideration for acquisitions was approximately $67.5 million, including the Company's interest in the above facilities and contingent consideration related to an acquisition made prior to 2012. The Company recognizes its proportionate share of the assets, liabilities, revenues and expenses related to the natural gas and oil midstream assets acquisition.

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 - Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In the second quarter of 2012, discontinued operations reflected the settlement of certain liabilities and estimated insurance recoveries resulting in a net benefit related to this matter. In the fourth quarter of 2012, the Company reversed its previously recorded accrual for the arbitration charge due to a favorable court ruling, which was partially offset by the reversal of estimated insurance recoveries. The Company incurred legal expenses and had a benefit related to the resolution of this matter in the second quarter of 2014. The Company also had a benefit related to income taxes, including the resolution of certain income tax matters, in the fourth quarter of 2014. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category.

Note 4 - Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. At December 31, 2014 and 2013, the Company had no significant equity method investments.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale of its entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE. The Company's remaining interest in ECTE is being sold over a multi-year period. In August 2013 and 2012, and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. The Company recognized immaterial gains in 2013 and 2012. The Company's remaining ownership interest in ECTE at December 31, 2014, accounted for under the cost method, was subsequently sold on January 26, 2015.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2014, were as follows:

	Balance at January 1, 2014 *	Goodwill Acquired During the Year/Other	Balance at December 31, 2014 *
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	104,276	(835)	103,441
Total	$ 636,039	$ (835)	$ 635,204

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

The changes in the carrying amount of goodwill for the year ended December 31, 2013, were as follows:

	Balance at January 1, 2013 *	Goodwill Acquired During the Year	Balance at December 31, 2013 *
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	104,276	—	104,276
Total	$ 636,039	$ —	$ 636,039

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

Other amortizable intangible assets at December 31 were as follows:

		2014		2013
		(In thousands)		
Customer relationships	$	21,310	$	21,310
Accumulated amortization		(15,556)		(13,726)
		5,754		7,584
Noncompete agreements		5,080		6,186
Accumulated amortization		(4,098)		(4,840)
		982		1,346
Other		10,921		10,995
Accumulated amortization		(7,817)		(6,826)
		3,104		4,169
Total	$	9,840	$	13,099

Amortization expense for amortizable intangible assets for the years ended December 31, 2014, 2013 and 2012, was $3.2 million, $4.0 million and $3.8 million, respectively. Estimated amortization expense for intangible assets is $2.5 million in 2015, $2.1 million in 2016, $1.9 million in 2017, $1.0 million in 2018, $900,000 in 2019 and $1.4 million thereafter.

Note 6 - Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period *		2014		2013
			(In thousands)		
Regulatory assets:					
Pension and postretirement benefits (a)	(e)	$	182,565	$	105,123
Taxes recoverable from customers (a)	Over plant lives		22,910		18,266
Manufactured gas plant sites remediation (a)	Up to 3 years		17,548		15,797
Natural gas costs recoverable through rate adjustments (b)	Up to 28 months		19,575		12,060
Long-term debt refinancing costs (a)	Up to 23 years		7,864		8,697
Costs related to identifying generation development (a)	Up to 12 years		4,165		4,512
Other (a) (b)	Largely within 1- 4 years		14,959		15,311
Total regulatory assets			269,586		179,766
Regulatory liabilities:					
Plant removal and decommissioning costs (c)			338,641		308,431
Taxes refundable to customers (c)			17,772		20,180
Natural gas costs refundable through rate adjustments (d)			13,238		16,932
Other (c) (d)			16,601		21,868
Total regulatory liabilities			386,252		367,411
Net regulatory position		$	(116,666)	$	(187,645)

*Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
(a) Included in deferred charges and other assets - other on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other liabilities on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred or cash contributions are made.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2014 and 2013, approximately $229.6 million and $163.7 million, respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2014 and 2013, credit risk was not material.

Fidelity

At December 31, 2014 and 2013, Fidelity held oil swap agreements with total forward notional volumes of 270,000 and 2.9 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 5.0 million and 18.3 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

Effective April 1, 2013, Fidelity elected to de-designate all commodity derivative contracts previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively for all of its commodity derivative instruments. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses and unrealized gains and losses are both recorded in operating revenues on the Consolidated Statements of Income. As a result of discontinuing hedge accounting on commodity derivative instruments, gains and losses on the oil and natural gas derivative instruments remain in accumulated other comprehensive income (loss) as of the de-designation date and are reclassified into earnings in future periods as the underlying hedged transactions affect earnings. At April 1, 2013, accumulated other comprehensive income (loss) included $1.8 million of unrealized gains, representing the mark-to-market value of the Company's commodity derivative instruments that qualified as cash flow hedges as of the balance sheet date, which the Company has subsequently reclassified into earnings.

Prior to April 1, 2013, changes in the fair value attributable to the effective portion of the hedging instruments, net of tax, were recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges were not effective or did not qualify for hedge accounting, the ineffective portion of the changes in fair market value was recorded directly in earnings. Gains and losses on the oil and natural gas derivative instruments were reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the oil and natural gas quantities were settled.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. Fidelity had no derivative instruments that were in a liability position with credit-risk-related contingent features at December 31, 2014. The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2013, was $7.5 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2013, was $7.5 million.

Centennial

Centennial has historically entered into interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. At December 31, 2014 and 2013, Centennial had no outstanding interest rate swap agreements.

Fidelity and Centennial

There were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur, and there were no such reclassifications.

The gains and losses on derivative instruments for the years ended December 31 were as follows:

	2014	2013	2012
		(In thousands)	
Commodity derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	$ —	$ (6,153)	$ 10,209
Amount of (gain) loss reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	295	(4,916)	(8,788)
Amount of loss recognized in operating revenues (ineffective portion), before tax	—	(1,422)	(730)
Interest rate derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	—	559	(1,712)
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	399	727	34
Amount of loss recognized in interest expense (ineffective portion), before tax	—	(769)	—
Commodity derivatives not designated as hedging instruments:			
Amount of gain (loss) recognized in operating revenues, before tax	23,400	(4,845)	106

Over the next 12 months net losses of approximately $400,000 (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, as the hedged transactions affect earnings.

The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2014	Fair Value at December 31, 2013
		(In thousands)	
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 18,335	$ 1,447
	Other assets - noncurrent	—	503
Total asset derivatives		$ 18,335	$ 1,950

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2014	Fair Value at December 31, 2013
		(In thousands)	
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ —	$ 7,483
Total liability derivatives		$ —	$ 7,483

All of the Company's commodity derivative instruments at December 31, 2014 and 2013, were subject to legally enforceable master netting agreements. However, the Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. The gross derivative assets and liabilities (excluding settlement receivables and payables that may be subject to the same master netting agreements) presented on the Consolidated Balance Sheets and the amount eligible for offset under the master netting agreements is presented in the following table:

December 31, 2014	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$ 18,335	$ —	$ 18,335
Total assets	$ 18,335	$ —	$ 18,335

December 31, 2013	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$ 1,950	$ (1,950)	$ —
Total assets	$ 1,950	$ (1,950)	$ —
Liabilities:			
Commodity derivatives	$ 7,483	$ (1,950)	$ 5,533
Total liabilities	$ 7,483	$ (1,950)	$ 5,533

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $65.8 million and $62.4 million as of December 31, 2014 and 2013, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2014, 2013 and 2012, were $3.4 million, $13.5 million and $5.2 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its available-for-sale securities, which include mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

December 31, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 6,594	$ 60	$ (18)	$ 6,636
U.S. Treasury securities	3,574	—	(19)	3,555
Total	$ 10,168	$ 60	$ (37)	$ 10,191

December 31, 2013	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 8,151	$ 69	$ (27)	$ 8,193
U.S. Treasury securities	1,906	15	(4)	1,917
Total	$ 10,057	$ 84	$ (31)	$ 10,110

The fair value of the Company's money market funds approximates cost.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company's Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

The estimated fair value of the Company's Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2014 and 2013, there were no transfers between Levels 1 and 2.

The Company's assets and liabilities measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
	(In thousands)			
Assets:				
Money market funds	$ —	$ 18,473	$ —	$ 18,473
Insurance contract*	—	65,831	—	65,831
Available-for-sale securities:				
Mortgage-backed securities	—	6,636	—	6,636
U.S. Treasury securities	—	3,555	—	3,555
Commodity derivative instruments	—	18,335	—	18,335
Total assets measured at fair value	$ —	$ 112,830	$ —	$ 112,830

*The insurance contract invests approximately 20 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies, 32 percent in fixed-income investments and 1 percent in cash equivalents.

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
		(In thousands)		
Assets:				
Money market funds	$ —	$ 19,227	$ —	$ 19,227
Insurance contract*	—	62,370	—	62,370
Available-for-sale securities:				
Mortgage-backed securities	—	8,193	—	8,193
U.S. Treasury securities	—	1,917	—	1,917
Commodity derivative instruments	—	1,950	—	1,950
Total assets measured at fair value	$ —	$ 93,657	$ —	$ 93,657
Liabilities:				
Commodity derivative instruments	$ —	$ 7,483	$ —	$ 7,483
Total liabilities measured at fair value	$ —	$ 7,483	$ —	$ 7,483

*The insurance contract invests approximately 29 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies and 15 percent in fixed-income investments.

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable. During the second quarters of 2013 and 2012, coalbed natural gas gathering assets were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2013, certain coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $9.7 million. The fair value of these coalbed natural gas gathering assets have been categorized as Level 3 (Significant Unobservable Inputs) in the fair value hierarchy.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2014		2013	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 2,094,727**	**$ 2,239,445**	$ 1,854,563	$ 1,912,590

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 9 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries:

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2014		Amount Outstanding at December 31, 2013		Letters of Credit at December 31, 2014	Expiration Date
							(In millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$	175.0	$	77.5 (b)	$	78.9 (b)	$	—	5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement	$	50.0 (c)	$	—	$	11.5	$	2.2 (d)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$	65.0 (e)	$	21.0	$	3.0	$	—	7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$	650.0	$	211.0 (b)	$	75.0 (b)	$	—	5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement	$	50.0 (g)	$	—	$	—	$	1.0 (d)	12/1/15

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million.
(d) An outstanding letter of credit reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $800.0 million). There were no amounts outstanding under the credit agreement.
(g) Certain provisions allow for increased borrowings up to a maximum of $75.0 million.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Dakota Prairie Refining, LLC On December 1, 2014, Dakota Prairie Refining entered into a $50.0 million revolving credit agreement with an expiration date of December 1, 2015.

The credit agreement contains customary covenants and provisions, including a covenant of Dakota Prairie Refining and its subsidiaries not to permit, as of the end of any fiscal quarter, the ratio of indebtedness to consolidated capitalization to be greater than 65 percent and a covenant of WBI Holdings and all of its subsidiaries not to permit, as of the end of any fiscal quarter, the ratio of funded debt to capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness, limitations on distributions and the making of certain investments.

Dakota Prairie Refining's credit agreement also contains cross-default provisions. These provisions state that if Dakota Prairie Refining or WBI Holdings fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the agreement will be in default.

Long-term debt

MDU Resources Group, Inc. On May 8, 2014, the Company amended the revolving credit agreement to increase the borrowing limit to $175.0 million and extend the termination date to May 8, 2019. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired; however, there is debt outstanding that is reflected in the following table of long-term debt outstanding. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Cascade Natural Gas Corporation Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the revolving credit agreement.

On January 15, 2015, Cascade issued $25.0 million of Senior Notes with due dates ranging from January 15, 2045 to January 15, 2055 at a weighted average interest rate of 4.2 percent.

Intermountain Gas Company Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

Centennial Energy Holdings, Inc. On May 8, 2014, Centennial entered into an amended and restated revolving credit agreement which increased the borrowing limit to $650.0 million and extended the termination date to May 8, 2019. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement and certain debt outstanding under an expired uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent (for the revolving credit agreement) and a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's EBITDA to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default.

On January 9, 2015, Centennial amended its letter of credit agreement for the issuance of up to approximately $28.0 million of letters of credit to extend the termination date to January 11, 2016.

WBI Energy Transmission, Inc. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2014, which reduced capacity under this uncommitted private shelf agreement. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

		2014		2013
		(In thousands)		
Senior Notes at a weighted average rate of 5.43%, due on dates ranging from June 19, 2015 to November 24, 2055	$	**1,636,662**	$	1,545,078
Commercial paper at a weighted average rate of .37%, supported by revolving credit agreements		**288,500**		153,924
Term Loan Agreements at a weighted average rate of 2.12%, due on dates ranging from April 22, 2018 to April 22, 2023		**72,000**		75,000
Medium-Term Notes at a weighted average rate of 7.32%, due on dates ranging from September 15, 2027 to March 16, 2029		**35,000**		35,000
Other notes at a weighted average rate of 5.23%, due on dates ranging from September 1, 2020 to February 1, 2035		**39,662**		39,863
Credit agreements at a weighted average rate of 3.47%, due on dates ranging from February 10, 2015 to November 30, 2038		**22,939**		5,701
Discount		**(36)**		(3)
Total long-term debt		**2,094,727**		1,854,563
Less current maturities		**269,449**		12,277
Net long-term debt	$	**1,825,278**	$	1,842,286

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2014, aggregate $269.4 million in 2015; $293.8 million in 2016; $51.0 million in 2017; $148.2 million in 2018; $345.7 million in 2019 and $986.6 million thereafter.

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of oil and natural gas wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

A reconciliation of the Company's liability, which is included in other accrued liabilities and other liabilities on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

		2014		2013
		(In thousands)		
Balance at beginning of year	$	**98,529**	$	102,545
Liabilities incurred		**5,416**		5,610
Liabilities acquired		**1,414**		—
Liabilities settled		**(18,388)**		(22,257)
Accretion expense		**4,605**		4,574
Revisions in estimates		**884**		7,671
Other		**379**		386
Balance at end of year	$	**92,839**	$	98,529

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2014 and 2013, was $2.3 million and $4.1 million, respectively. The legally restricted assets consist primarily of money market funds and are reflected in other assets on the Consolidated Balance Sheets.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

		2014		2013
		(In thousands, except shares and per share amounts)		
Authorized:				
Preferred -				
500,000 shares, cumulative, par value $100, issuable in series				
Preferred stock A -				
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)				
Preference -				
500,000 shares, cumulative, without par value, issuable in series (none outstanding)				
Outstanding:				
4.50% Series - 100,000 shares	$	**10,000**	$	10,000
4.70% Series - 50,000 shares		**5,000**		5,000
Total preferred stocks	$	**15,000**	$	15,000

For the years 2014, 2013 and 2012, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 12 - Common Stock

For the years 2014, 2013 and 2012, dividends declared on common stock were $.7150, $.6950 and $.6750 per common share, respectively.

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2014 to December 2014, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2012 through December 2013, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2014, there were 14.9 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes, excluding noncash write-downs, for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately \$2.3 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2014. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately \$259 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2014. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2014, there are 5.6 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense (after tax) was \$4.4 million, \$3.9 million and \$4.0 million in 2014, 2013 and 2012, respectively.

As of December 31, 2014, total remaining unrecognized compensation expense related to stock-based compensation was approximately \$8.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 43,088 shares with a fair value of \$1.1 million, 36,713 shares with a fair value of \$1.1 million and 53,888 shares with a fair value of \$1.1 million issued under this plan during the years ended December 31, 2014, 2013 and 2012, respectively.

A key employee of the Company received an award of 43,103 shares of common stock under a long-term incentive plan with a fair value of \$930,000 during the year ended December 31, 2012.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2014, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2012	2012-2014	251,196
March 2013	2013-2015	240,419
February 2014	2014-2016	196,840

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2014, 2013 and 2012 were:

			2014			2013			2012
Grant-date fair value			\$41.13			\$29.01			\$17.18
Blended volatility range	18.94%	–	20.43%	16.10%	–	19.39%	24.29%	–	25.81%
Risk-free interest rate range	.03%	–	.74%	.09%	–	.40%	.10%	–	.35%
Discounted dividends per share			\$2.15			\$2.12			\$1.19

The fair value of the performance shares that vested during the year ended December 31, 2014, was $16.6 million. There were no performance shares that vested in 2013 or 2012.

A summary of the status of the performance share awards for the year ended December 31, 2014, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	749,991	$	21.99
Granted	196,840		41.13
Additional performance shares earned	236,699		19.99
Vested	(491,213)		19.99
Forfeited	(3,862)		29.01
Nonvested at end of period	688,455	$	28.16

Note 14 - Income Taxes

The components of income (loss) before income taxes from continuing operations for each of the years ended December 31 were as follows:

		2014		2013		2012
				(In thousands)		
United States	$	**411,182**	$	415,202	$	(47,175)
Foreign		**(52)**		416		1,708
Income (loss) before income taxes from continuing operations	$	**411,130**	$	415,618	$	(45,467)

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

		2014		2013		2012
				(In thousands)		
Current:						
Federal	$	**32,726**	$	45,518	$	(26,858)
State		**5,390**		4,311		858
Foreign		**—**		(29)		(75)
		38,116		49,800		(26,075)
Deferred:						
Income taxes:						
Federal		**81,017**		78,953		(1,224)
State		**4,989**		8,031		(6,323)
Investment tax credit - net		**1,009**		(206)		44
		87,015		86,778		(7,503)
Change in uncertain tax positions		**(5,183)**		—		1,974
Change in accrued interest		**21**		158		458
Total income tax expense (benefit)	$	**119,969**	$	136,736	$	(31,146)

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2014	2013
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 134,567	$ 125,607
Accrued pension costs	97,690	74,320
Alternative minimum tax credit carryforward	23,844	33,304
Compensation-related	38,654	31,550
Asset retirement obligations	34,296	29,578
Legal and environmental contingencies	10,049	10,710
Other	59,389	45,101
Total deferred tax assets	398,489	350,170
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	906,455	813,597
Basis differences on oil and natural gas producing properties	270,939	266,168
Regulatory matters	97,521	64,914
Intangible asset amortization	22,505	13,579
Other	29,676	26,170
Total deferred tax liabilities	1,327,096	1,184,428
Net deferred income tax liability	$ (928,607)	$ (834,258)

As of December 31, 2014 and 2013, no valuation allowance has been recorded associated with the previously identified deferred tax assets. The alternative minimum tax credit carryforwards do not expire.

The following table reconciles the change in the net deferred income tax liability from December 31, 2013, to December 31, 2014, to deferred income tax expense:

	2014
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 94,349
Deferred taxes associated with other comprehensive loss	2,360
Other	(9,694)
Deferred income tax expense for the period	$ 87,015

Total income tax expense (benefit) differs from the amount computed by applying the statutory federal income tax rate to income (loss) before taxes. The reasons for this difference were as follows:

Years ended December 31,	2014		2013		2012	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$ 143,895	35.0	$ 145,466	35.0	$ (15,914)	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	10,483	2.5	10,524	2.5	2,469	(5.4)
Domestic production activities	(5,460)	(1.3)	(677)	(.2)	—	—
Nonqualified benefit plans	(1,624)	(.4)	(5,173)	(1.2)	(2,359)	5.2
Depletion allowance	(4,010)	(1.0)	(3,764)	(.9)	(3,728)	8.2
Federal renewable energy credit	(3,655)	(.9)	(3,404)	(.8)	(3,401)	7.5
Deductible K-Plan dividends	(2,062)	(.5)	(1,593)	(.4)	(2,829)	6.2
AFUDC equity	(2,031)	(.5)	(1,074)	(.3)	(1,500)	3.3
Resolution of tax matters and uncertain tax positions	(7,367)	(1.8)	(859)	(.2)	2,559	(5.6)
Deferred tax rate changes	9	—	741	.2	(3,083)	6.8
Other	(8,209)	(1.9)	(3,451)	(.8)	(3,360)	7.3
Total income tax expense (benefit)	$ 119,969	29.2	$ 136,736	32.9	$ (31,146)	68.5

The income tax benefit in 2012 resulted largely from the Company's write-downs of oil and natural gas properties, as discussed in Note 1.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $3.6 million at December 31, 2014. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2014, was approximately $1.4 million.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. The Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007. The Company and the Internal Revenue Service have agreed to a settlement for the 2007 through 2009 tax years.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

		2014	2013	2012
			(In thousands)	
Balance at beginning of year	$	**14,914** $	14,914 $	11,206
Additions for tax positions of prior years		**—**	—	3,708
Settlements		**(14,777)**	—	—
Balance at end of year	$	**137** $	14,914 $	14,914

Included in the balance of unrecognized tax benefits at December 31, 2013, was $8.4 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $155,000, including approximately $18,000 for the payment of interest and penalties at December 31, 2014, and was $9.0 million, including approximately $2.5 million for the payment of interest and penalties at December 31, 2013.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2014, will be settled in the next twelve months.

For the years ended December 31, 2014, 2013 and 2012, the Company recognized approximately $1.8 million, $1.2 million and $740,000, respectively, in interest expense. Penalties were not material in 2014, 2013 and 2012. The Company recognized interest income of approximately $540,000, $660,000 and $290,000 for the years ended December 31, 2014, 2013 and 2012, respectively. The Company had accrued liabilities of approximately $1.8 million and $2.8 million at December 31, 2014 and 2013, respectively, for the payment of interest.

Note 15 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States. The Company also has an investment in a foreign country, which consists of Centennial Resources' investment in ECTE. For more information, see Note 4.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline and energy services segment provides natural gas transportation, underground storage, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment is constructing Dakota Prairie Refinery in conjunction with Calumet to refine crude oil and also provides cathodic protection and other energy-related services.

The exploration and production segment is engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. The Company intends to market its exploration and production business in the future. The plan to market this business has been delayed due to low oil prices.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability, automobile liability and pollution liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' investment in ECTE.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2014	2013	2012
		(In thousands)	
External operating revenues:			
Electric	**$ 277,874**	$ 257,260	$ 236,895
Natural gas distribution	**921,986**	851,945	754,848
Pipeline and energy services	**166,496**	155,369	139,883
	1,366,356	1,264,574	1,131,626
Exploration and production	**500,526**	490,924	412,651
Construction materials and contracting	**1,740,089**	1,675,444	1,597,257
Construction services	**1,062,055**	1,029,909	932,013
Other	**1,532**	1,553	1,884
	3,304,202	3,197,830	2,943,805
Total external operating revenues	**$ 4,670,558**	$ 4,462,404	$ 4,075,431
Intersegment operating revenues:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and energy services	**49,372**	46,699	53,274
Exploration and production	**47,045**	45,099	35,966
Construction materials and contracting	**25,241**	36,693	20,168
Construction services	**57,474**	9,930	6,545
Other	**7,832**	8,067	8,486
Intersegment eliminations	**(186,964)**	(146,488)	(124,439)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 35,008**	$ 32,789	$ 32,509
Natural gas distribution	**54,700**	50,031	45,731
Pipeline and energy services	**30,645**	29,119	27,684
Exploration and production	**198,199**	186,458	160,681
Construction materials and contracting	**68,557**	74,470	79,527
Construction services	**12,874**	11,939	11,063
Other	**2,196**	2,050	2,010
Intersegment eliminations	**(811)**	—	—
Total depreciation, depletion and amortization	**$ 401,368**	$ 386,856	$ 359,205

	2014	2013	2012
		(In thousands)	
Interest expense:			
Electric	$ 15,595	$ 12,590	$ 12,421
Natural gas distribution	27,217	25,123	28,726
Pipeline and energy services	10,048	10,330	7,742
Exploration and production	13,834	14,315	9,018
Construction materials and contracting	16,368	17,394	15,211
Construction services	4,176	4,306	4,435
Other	15	15	13
Intersegment eliminations	(237)	(156)	(867)
Total interest expense	$ 87,016	$ 83,917	$ 76,699
Income taxes:			
Electric	$ 12,442	$ 9,683	$ 8,975
Natural gas distribution	11,350	16,633	12,005
Pipeline and energy services	9,699	3,390	15,291
Exploration and production	47,739	53,197	(108,264)
Construction materials and contracting	18,586	24,765	14,099
Construction services	24,753	29,504	24,128
Other	(1,119)	2,433	2,620
Intersegment eliminations	(3,481)	(2,869)	—
Total income taxes	$ 119,969	$ 136,736	$ (31,146)
Earnings (loss) on common stock:			
Electric	$ 36,731	$ 34,837	$ 30,634
Natural gas distribution	30,484	37,656	29,409
Pipeline and energy services	22,628	7,629	26,588
Exploration and production	96,733	94,450	(177,283)
Construction materials and contracting	51,510	50,946	32,420
Construction services	54,432	52,213	38,429
Other	7,461	5,136	4,797
Intersegment eliminations	(5,608)	(4,307)	—
Earnings (loss) on common stock before income (loss) from discontinued operations	294,371	278,560	(15,006)
Income (loss) from discontinued operations, net of tax*	3,177	(312)	13,567
Total earnings (loss) on common stock	$ 297,548	$ 278,248	$ (1,439)
Capital expenditures:			
Electric	$ 185,121	$ 168,557	$ 112,035
Natural gas distribution	120,613	101,279	130,178
Pipeline and energy services	177,409	127,092	133,787
Exploration and production	600,572	391,315	554,528
Construction materials and contracting	37,896	34,607	45,083
Construction services	26,942	15,102	14,835
Other	2,131	2,249	791
Net proceeds from sale or disposition of property and other	(306,994)	(112,131)	(57,460)
Total net capital expenditures	$ 843,690	$ 728,070	$ 933,777
Assets:			
Electric**	$ 1,030,611	$ 884,283	$ 760,324
Natural gas distribution**	1,931,908	1,786,068	1,703,459
Pipeline and energy services	1,081,902	798,701	622,470
Exploration and production	1,738,064	1,616,131	1,539,017
Construction materials and contracting	1,272,231	1,305,808	1,371,252
Construction services	454,602	450,614	429,547
Other***	300,660	219,727	256,422
Total assets	$ 7,809,978	$ 7,061,332	$ 6,682,491

	2014	2013	2012
		(In thousands)	
Property, plant and equipment:			
Electric**	$ 1,457,101	$ 1,315,822	$ 1,150,584
Natural gas distribution**	1,904,759	1,776,901	1,689,950
Pipeline and energy services	1,220,233	962,172	816,533
Exploration and production	3,402,879	3,060,848	2,764,560
Construction materials and contracting	1,529,942	1,510,355	1,504,981
Construction services	144,395	134,948	130,624
Other	50,937	49,997	50,519
Eliminations	(17,075)	(7,177)	—
Less accumulated depreciation, depletion and amortization	4,166,407	3,872,487	3,608,912
Net property, plant and equipment	$ 5,526,764	$ 4,931,379	$ 4,498,839

* Reflected in the Other category.

** Includes allocations of common utility property.

*** Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

Note: The results reflect $391.8 million ($246.8 million after tax) of noncash write-downs of oil and natural gas properties in 2012.

Excluding the impairments of the coalbed natural gas gathering assets of $9.0 million (after tax) and $1.7 million (after tax) in 2013 and 2012, respectively, and the reversal of the charge related to natural gas gathering operations litigation of $1.5 million (after tax) and $15.0 million (after tax) in 2013 and 2012, respectively, as discussed in Notes 1 and 19, respectively, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2014, 2013 and 2012 include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. The net transactions were $(61.2) million in 2014, $(56.8) million in 2013 and $33.7 million in 2012.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. In 2010, all benefit and service accruals for nonunion and certain union plans were frozen. In 2011 and 2012, all benefit and service accruals for certain additional union employees were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who had attained age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits at certain of the Company's businesses.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage was replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through an exchange.

Changes in benefit obligation and plan assets for the years ended December 31, 2014 and 2013, and amounts recognized in the Consolidated Balance Sheets at December 31, 2014 and 2013, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 402,772**	$ 459,111	**$ 81,726**	$ 103,358
Service cost	**129**	155	**1,518**	1,675
Interest cost	**17,682**	16,249	**3,521**	3,215
Plan participants' contributions	**—**	—	**1,399**	1,472
Actuarial (gain) loss	**80,520**	(44,551)	**18,024**	(20,985)
Benefits paid	**(25,766)**	(28,192)	**(7,176)**	(7,009)
Benefit obligation at end of year	**475,337**	402,772	**99,012**	81,726
Change in net plan assets:				
Fair value of plan assets at beginning of year	**334,844**	309,184	**84,543**	74,361
Actual gain on plan assets	**24,500**	35,539	**7,527**	13,819
Employer contribution	**20,785**	18,313	**1,293**	1,900
Plan participants' contributions	**—**	—	**1,399**	1,472
Benefits paid	**(25,766)**	(28,192)	**(7,176)**	(7,009)
Fair value of net plan assets at end of year	**354,363**	334,844	**87,586**	84,543
Funded status - (under) over	**$ (120,974)**	$ (67,928)	**$ (11,426)**	$ 2,817
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ —**	$ —	**$ 4,345**	$ 9,679
Other accrued liabilities (current)	**—**	—	**(322)**	(381)
Other liabilities (noncurrent)	**(120,974)**	(67,928)	**(15,449)**	(6,481)
Net amount recognized	**$ (120,974)**	$ (67,928)	**$ (11,426)**	$ 2,817
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 207,430**	$ 135,061	**$ 25,779**	$ 11,314
Prior service cost (credit)	**294**	365	**(15,744)**	(17,137)
Total	**$ 207,724**	$ 135,426	**$ 10,035**	$ (5,823)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 6.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation was amortized over a 20-year period ending 2012.

The pension plans all have accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2014	2013
	(In thousands)	
Projected benefit obligation	**$ 475,337**	$ 402,772
Accumulated benefit obligation	**$ 475,337**	$ 402,772
Fair value of plan assets	**$ 354,363**	$ 334,844

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	**2014**	2013	2012
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	$ **129**	$ 155	$ 1,078	$ **1,518**	$ 1,675	$ 1,747
Interest cost	**17,682**	16,249	17,598	**3,521**	3,215	4,166
Expected return on assets	**(21,218)**	(19,917)	(23,536)	**(4,617)**	(4,343)	(4,890)
Amortization of prior service cost (credit)	**71**	71	(46)	**(1,393)**	(1,457)	(1,438)
Recognized net actuarial loss	**4,869**	7,173	7,070	**649**	1,814	2,134
Curtailment gain	**—**	—	(1,023)	**—**	—	—
Amortization of net transition obligation	**—**	—	—	**—**	—	2,128
Net periodic benefit cost (credit), including amount capitalized	**1,533**	3,731	1,141	**(322)**	904	3,847
Less amount capitalized	**388**	727	937	**(21)**	164	910
Net periodic benefit cost (credit)	**1,145**	3,004	204	**(301)**	740	2,937
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**77,238**	(60,173)	19,982	**15,114**	(30,461)	1,863
Prior service credit	**—**	—	—	**—**	—	(11,418)
Amortization of actuarial loss	**(4,869)**	(7,173)	(7,070)	**(649)**	(1,814)	(2,134)
Amortization of prior service (cost) credit	**(71)**	(71)	1,069	**1,393**	1,457	1,438
Amortization of net transition obligation	**—**	—	—	**—**	—	(2,128)
Total recognized in accumulated other comprehensive (income) loss	**72,298**	(67,417)	13,981	**15,858**	(30,818)	(12,379)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	$ **73,443**	$ (64,413)	$ 14,185	$ **15,557**	$ (30,078)	$ (9,442)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $7.1 million and $71,000, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $1.8 million and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
Discount rate	**3.70%**	4.53%	**3.74%**	4.48%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%
Rate of compensation increase	**N/A**	N/A	**3.00%**	3.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
Discount rate	**4.53%**	3.65%	**4.48%**	3.67%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%
Rate of compensation increase	**N/A**	N/A	**3.00%**	4.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2014, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to

75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2014	2013
Health care trend rate assumed for next year	4.0% – 7.0%	6.0% – 7.0%
Health care cost trend rate - ultimate	5.0% – 6.0%	5.0% – 6.0%
Year in which ultimate trend rate achieved	2017	2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over six percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2014:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 247	$ (207)
Effect on postretirement benefit obligation	$ 4,489	$ (3,832)

The Company's pension assets are managed by 15 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's pension plans' assets are determined using the market approach.

The carrying value of the pension plans' Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high quality, short-term instruments of domestic and foreign issuers. There are no unfunded commitments related to this fund.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. Units of these funds can be redeemed on a daily basis at their net asset value and have no redemption restrictions. There are no unfunded commitments related to these funds.

The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data.

The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market.

The estimated fair value of the pension plans' Level 2 U.S. Government securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2014 and 2013, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plans' assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 5,631	$ —	$ 5,631
Equity securities:				
U.S. companies	39,077	—	—	39,077
International companies	5,189	—	—	5,189
Collective and mutual funds*	132,403	77,449	—	209,852
Corporate bonds	—	59,471	—	59,471
Municipal bonds	—	10,462	—	10,462
U.S. Government securities	15,001	6,849	—	21,850
Total assets measured at fair value	$ 191,670	$ 159,862	$ —	$ 351,532

*Collective and mutual funds invest approximately 13 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Government securities, 23 percent in corporate bonds, 33 percent in common stock of international companies and 18 percent in other investments.

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 9,406	$ —	$ 9,406
Equity securities:				
U.S. companies	62,599	—	—	62,599
International companies	39,437	—	—	39,437
Collective and mutual funds*	116,265	42,483	—	158,748
Corporate bonds	—	42,721	—	42,721
Municipal bonds	—	7,561	—	7,561
U.S. Government securities	7,487	4,335	—	11,822
Total assets measured at fair value	$ 225,788	$ 106,506	$ —	$ 332,294

*Collective and mutual funds invest approximately 11 percent in common stock of mid-cap U.S. companies, 19 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Government securities, 27 percent in corporate bonds, 13 percent in common stock of international companies and 18 percent in other investments.

The estimated fair values of the Company's other postretirement benefit plans' assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to this fund.

The estimated fair value of the other postretirement benefit plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the other postretirement benefit plans' Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2014 and 2013, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,097	$ —	$ 2,097
Equity securities:				
U.S. companies	2,614	—	—	2,614
International companies	25	—	—	25
Insurance contract*	—	82,846	—	82,846
Total assets measured at fair value	$ 2,639	$ 84,943	$ —	$ 87,582

*The insurance contract invests approximately 54 percent in common stock of large-cap U.S. companies, 11 percent in U.S. Government securities, 10 percent in mortgage-backed securities, 10 percent in corporate bonds and 15 percent in other investments.

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,142	$ —	$ 2,142
Equity securities:				
U.S. companies	2,802	—	—	2,802
International companies	221	—	—	221
Insurance contract*	—	79,374	—	79,374
Total assets measured at fair value	$ 3,023	$ 81,516	$ —	$ 84,539

*The insurance contract invests approximately 55 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Government securities, 8 percent in mortgage-backed securities, 8 percent in common stock of mid-cap U.S. companies, 9 percent in corporate bonds and 8 percent in other investments.

The Company expects to contribute approximately $3.9 million to its defined benefit pension plans and approximately $400,000 to its postretirement benefit plans in 2015.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years		Pension Benefits		Other Postretirement Benefits		Expected Medicare Part D Subsidy
				(In thousands)		
2015	$	23,769	$	5,162	$	218
2016		24,025		5,186		213
2017		24,621		5,262		207
2018		25,064		5,329		200
2019		25,498		5,344		193
2020 - 2024		133,935		26,714		836

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company's net periodic benefit cost for these plans was $6.6 million, $7.3 million and $8.1 million in 2014, 2013 and 2012, respectively. The total projected benefit obligation for these plans was $115.6 million and $106.9 million at December 31, 2014 and 2013, respectively. The accumulated benefit obligation for these plans was $108.2 million and $99.7 million at December 31, 2014 and 2013, respectively. A weighted average discount rate of 3.51 percent and 4.32 percent at December 31, 2014 and 2013, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent at December 31, 2014 and 2013, were used to determine benefit obligations. A discount rate of 4.32 percent and 3.44 percent at December 31, 2014 and 2013, respectively, and a rate of compensation increase of 4.00 percent and 3.00 percent at December 31, 2014 and 2013, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $6.6 million in 2015; $6.5 million in 2016; $6.7 million in 2017; $7.1 million in 2018; $7.3 million in 2019 and $37.9 million for the years 2020 through 2024.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2014 and 2013 were $104,000 and $25,000, respectively.

The Company had investments of $101.4 million and $98.1 million at December 31, 2014 and 2013, respectively, consisting of equity securities of $54.9 million and $53.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $32.8 million and $31.4 million, respectively, and other investments of $13.7 million and $13.2 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $34.4 million in 2014, $33.2 million in 2013 and $29.3 million in 2012.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its MEPPs, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2014 and 2013 is for the plan's year-end at December 31, 2013, and December 31, 2012, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2014	Pension Protection Act Zone Status 2013	FIP/RP Status Pending/ Implemented	Contributions 2014	Contributions 2013	Contributions 2012	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green as of 12/31/2014	Green as of 12/31/2013	No	$ **9,061**	$ 6,358	$ 5,171	No	12/31/2014*
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2014	Yellow as of 4/30/2013	Implemented	**777**	1,041	2,771	No	4/23/2017
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2014	Red as of 6/30/2013	Implemented	**1,392**	1,284	1,093	No	11/29/2015
IBEW Local No. 246 Pension Plan	34-6582842-001	Yellow as of 5/31/2014	Yellow as of 5/31/2013	Implemented	**694**	1,848	1	No	10/31/2017
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2014	Red as of 2/28/2013	Implemented	**1,110**	1,489	564	No	8/31/2015
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2014	Yellow as of 5/31/2013	Implemented	**663**	921	567	No	6/30/2016
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**6,476**	5,883	5,603	No	11/30/2019
OE Pension Trust Fund	94-6090764-001	Red as of 12/31/2014	Yellow	Implemented	**1,445**	1,510	1,156	No	6/15/2015–6/30/2016
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming**	83-6011320-001	Red as of 12/31/2014	Red as of 12/31/2013	Implemented	**68**	76	91	No	10/31/2005*
Operating Engineers Pension Trust	95-6032478-001	Red as of 6/30/2014	Red as of 6/30/2013	Implemented	**612**	493	761	No	7/1/2016
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2014	Red as of 12/31/2013	Implemented	**676**	512	467	No	6/30/2015
Southwest Marine Pension Trust	95-6123404-001	Red as of 12/31/2014	Red as of 12/31/2013	Implemented	**31**	42	76	No	1/31/2014*–1/31/2019
Other funds					**19,812**	17,803	16,458		
Total contributions					$ **42,817**	$ 39,260	$ 34,779		

* Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.
** The Company withdrew from the plan as of October 26, 2014, as discussed below.

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2013 and 2012
IBEW Local 38 Pension Plan	2012
IBEW Local No. 82 Pension Plan	2013 and 2012
Local Union No. 124 IBEW Pension Trust Fund	2013 and 2012
Local Union 212 IBEW Pension Trust Fund	2013 and 2012
IBEW Local Union No. 357 Pension Plan A	2013 and 2012
IBEW Local 648 Pension Plan	2013 and 2012
Idaho Plumbers and Pipefitters Pension Plan	2012
Minnesota Teamsters Construction Division Pension Fund	2013 and 2012
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming*	2013 and 2012
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2013 and 2012

* The Company withdrew from the plan as of October 26, 2014, as discussed below.

On September 24, 2014, Knife River provided notice to the Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming that it was withdrawing from the plan effective October 26, 2014. The plan administrator will determine Knife River's withdrawal liability, which the Company currently estimates at approximately $14 million (approximately $8.4 million after tax). The assessed withdrawal liability for this plan may be significantly different from the current estimate.

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $34.6 million, $37.1 million and $31.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Amounts contributed in 2014, 2013 and 2012 to defined contribution multiemployer plans were $22.0 million, $20.6 million and $18.7 million, respectively.

Note 17 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance and taxes, other than income) in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2014	2013
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 64,283	$ 63,890
Less accumulated depreciation	43,043	41,323
	$ 21,240	$ 22,567
Coyote Station:		
Utility plant in service	$ 138,810	$ 138,261
Less accumulated depreciation	94,443	89,528
	$ 44,367	$ 48,733
Wygen III:		
Utility plant in service	$ 65,597	$ 64,332
Less accumulated depreciation	5,928	4,639
	$ 59,669	$ 59,693

Note 18 - Regulatory Matters and Revenues Subject to Refund

On August 11, 2014, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $3.0 million annually or approximately 3.6 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, depreciation and taxes associated with the increased investment as well as an increase in Montana-Dakota's operation and maintenance expenses. On February 3, 2015, the MTPSC approved an interim increase of $2.0 million or approximately 2.3 percent, subject to refund, to be effective with service rendered on and after February 6, 2015. The MTPSC has scheduled a hearing for this matter on March 25, 2015.

On October 3, 2014, Montana-Dakota filed an application with the WYPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $788,000 annually or approximately 4.1 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities and the associated operation and maintenance expenses, depreciation and taxes associated with the increase in investment. The WYPSC has scheduled a hearing for this matter on May 19, 2015.

On November 14, 2014, Montana-Dakota filed an application with the NDPSC for approval to implement the rate adjustment associated with the electric generation resource recovery rider approved by the NDPSC on August 20, 2014. On January 7, 2015, the NDPSC approved the rate adjustments of $5.3 million annually to be effective with service rendered on and after January 9, 2015.

On December 22, 2014, Montana-Dakota filed an application for advance determination of prudence and a certificate of public convenience and necessity with the NDPSC for the Thunder Spirit Wind project. This project will provide energy, capacity and renewable energy credits to Montana-Dakota's electric customers in North Dakota, Montana and South Dakota.

On February 6, 2015, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $4.3 million annually or approximately 3.4 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, depreciation and taxes associated with the increased investment as well as an increase in Montana-Dakota's operation and maintenance expenses. Montana-Dakota requested an interim increase of $4.3 million or 3.4 percent, subject to refund. This matter is pending before the NDPSC.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $27.6 million and $29.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2014 and 2013, respectively, which include amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Construction Materials Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company filed an application for amendment of its opencut mining permit and intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Former Employee Litigation On August 6, 2012, a former employee and his spouse filed actions against Connolly-Pacific and others in California Superior Court alleging the former employee contracted acute myelogenous leukemia from exposure to substances while employed as a seaman by the defendants. The plaintiffs request compensatory damages of approximately $23.8 million plus punitive damages, costs and interest. Connolly-Pacific is contesting the claims and believes it has meritorious defenses to them. Connolly-Pacific will seek insurance coverage for defense costs and any liability incurred in the litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel WBI Energy Midstream to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of WBI Energy Midstream's pipeline gathering systems in Montana. WBI Energy Midstream resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered WBI Energy Midstream into arbitration. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, WBI Energy Midstream, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010. On April 20, 2011, the Colorado State District Court confirmed the arbitration award as a court judgment. WBI Energy Midstream filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals. The Colorado Court of Appeals issued a decision on May 24, 2012, reversing the Colorado State District Court order compelling arbitration, vacating the final award and remanding the case to the Colorado State District Court to determine SourceGas's claims and WBI Energy Midstream's counterclaims. As a result of the Colorado Court of Appeals decision, in the second quarter of 2012, WBI Energy Midstream changed its estimated loss related to this matter. This resulted in a reduction of expense of $24.1 million ($15.0 million after tax), which was largely reflected in operation and maintenance expense on the Consolidated Statements of Income. On August 2, 2012, SourceGas filed a petition for writ of certiorari with the Colorado Supreme Court for review of the Colorado Court of Appeals decision which was denied on July 22, 2013. On remand of the matter to the Colorado State District Court, SourceGas may assert claims similar to those asserted in the arbitration proceeding.

THIS FILING IS		
Item 1: ■ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

SUPPLEMENTAL REPORT TO

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Cascade Natural Gas Corporation	**End of** 2014/Q4

Supplemental Report To
Washington Utilities & Transportation Commission

TABLE OF CONTENTS

GAS COMPANIES
2014
ANNUAL REPORT

FOR

Cascade Natural Gas Corporation

(NAME UNDER WHICH CORPORATION, PARTNERSHIP, OR INDIVIDUAL IS DOING BUSINESS)

8113 W. Grandridge Blvd.

(OFFICIAL MAILING ADDRESS)

Kennewick	WA	99336-7166
(CITY)	(STATE)	(ZIP)

☐ Please check if address listed above is an updated address

Report Year Ended: December 31, 2014

Inquiries concerning this Annual Report should be addressed to:

Name/Title:	Tammy Nygard / Director, Accounting & Finance
Address:	8113 W. Grandridge Blvd.
City:	Kennewick
State/Zip:	WA 99336-7166
Telephone:	(509) 734-4516
Email:	tammy.nygard@cngc.com

SUBMIT TO:
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
PO Box 47250
Olympia, WA 98504-7250

File online: www.utc.wa.gov

WASHINGTON UTC UTILITIES AND TRANSPORTATION COMMISSION

REPORT MUST BE RECEIVED NO LATER THAN MAY 1, 2015

Please refer to the Instructions for Completing the Annual Report on Page 2

ANNUAL REPORT CERTIFICATION

(PLEASE VERIFY THAT ALL SCHEDULES ARE ACCURATE AND COMPLETE BEFORE SIGNING)

I, the undersigned Tammy Nygard
Responsible Account Officer (Please Print)

of Cascade Natural Gas Corporation
Name of Company

have examined the foregoing report; that, to the best of my knowledge and belief, all statement of fact contained in said report are true and said report is a correct statement of the business and affairs of the above-named respondent in respect to each and every matter set forth therein during the period from January 1, 2014, to December 31, 2014, inclusive.

Director, Accounting & Finance	Tammy Nygard
Title (please print)	Signature (please type if filing electronically)
(509) 734-4516	3/9/2015
Telephone Number	Date

GENERAL INFORMATION

Washington Unified Business Identifier (UBI) No.: 578-012-249

(If you do not know your UBI No. please contact Business Licensing Service at 1-800-451-7985 or BLS@dor.wa.gov)

Business Structure (*please check the appropriate designation*):

☐ Individual / Sole Proprietor ☐ Partnership ☐ Other (LP, LLP, LLC) ☑ Corporation ☐ Nonprofit Corporation

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR/PERIOD OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2014

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting mehods made during the year which had an effect on ne income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance For Quarter/Year (c)	Total Prior Year to Date Balance For Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Gas Operating Revenues (400)	300-301	$ 237,939,987	$ 213,341,409		
3	Operating Expenses					
4	Operation Expenses (401)	317-325	171,814,436	146,579,979		
5	Maintenance Expenses (402)	317-325	4,625,270	4,346,626		
6	Depreciation Expense (403)	336-338	15,261,616	14,922,469		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	-	-		
8	Amortization and Depletion of Utility Plant (404-405)	336-338	1,644,958	1,149,283		
9	Amortization of Utility Plant Acq. Adjustment (406)	336-338	-	-		
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		-	-		
11	Amortization of Conversion Expenses (407.2)		-	-		
12	Regulatory Debits (407.3)		-	-		
13	(Less) Regulatory Credits (407.4)		-	-		
14	Taxes Other Than Income Taxes (408.1)	262-263	24,370,751	21,930,758		
15	Income Taxes-Federal (409.1)	262-263	(4,989,631)	(353,117)		
16	Income Taxes-Other (409.1)	262-263	-	-		
17	Provision for Deferred Income Taxes (410.1)	234-235	9,687,352	6,324,589		
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	-	-		
19	Investment Tax Credit Adjustment - Net (411.4)		(44,458)	(48,403)		
20	(Less) Gains from Disposition of Utility Plant (411.6)		-	-		
21	Losses from Disposition of Utility Plant (411.7)		-	-		
22	(Less) Gains from Disposition of Allowances (411.8)		-	-		
23	Losses from Disposition of Allowances (411.9)		-	-		
24	Accretion Expense (411.10)		-	-		
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		222,370,294	194,852,184		
26	Net Utility Operating Income (Enter Total of line 2 less 25) (Carry forward to page 116, line 27)		15,569,693	18,489,225		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR/PERIOD OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2014

STATEMENT OF INCOME

Line No.	Electric Utilitly Current Year to Date (in dollars) (g)	Electric Utilitly Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	-	-	237,939,987	213,341,409	-	-
3						
4	-	-	171,814,436	146,579,979	-	-
5	-	-	4,625,270	4,346,626	-	-
6	-	-	15,261,616	14,922,469	-	-
7						
8	-	-	1,644,958	1,149,283	-	-
9	-	-	-	-	-	-
10	-	-	-	-	-	-
11	-	-	-	-	-	-
12	-	-	-	-	-	-
13	-	-	-	-	-	-
14	-	-	24,370,751	21,930,758	-	-
15	-	-	(4,989,631)	(353,117)	-	-
16	-	-	-	-	-	-
17	-	-	9,687,352	6,324,589	-	-
18	-	-	-	-	-	-
19	-	-	(44,458)	(48,403)	-	-
20	-	-	-	-	-	-
21	-	-	-	-	-	-
22	-	-	-	-	-	-
23	-	-	-	-	-	-
24	-	-	-	-	-	-
25	-	-	222,370,294	194,852,184	-	-
26	-	-	15,569,693	18,489,225	-	-

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2014

STATEMENT OF INCOME FOR THE YEAR

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance For Quarter/Year (c)	Total Prior Year to Date Balance For Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried fwd. from page 114)		15,569,693	18,489,225		
28	**OTHER INCOME AND DEDUCTIONS**					
29	Other Income					
30	Nonutility Operating Income					
31	Rev. From Merchandising, Jobbing & Contract Work (415)		-	-		
32	(Less) Costs & Exp. of Merch., Job. & Contr. Work (416)		-	-		
33	Revenues From Nonutility Operations (417)		16,772	17,287		
34	(Less) Expenses of Nonutilty Operations (417.1)		-	-		
35	Nonoperating Rental Income (418)		-	-		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-	-		
37	Interest and Dividend Income (419)		358,649	198,705		
38	Allowance for Other Finds Used During Construction (419.1)		278,237	9,489		
39	Miscellaneous Nonoperating Income (421)		30,800	17,408		
40	Gain on Disposition of Property (421.1)		-	-		
41	TOTAL Other Income (Total of Lines 31 thru 40)		684,458	242,889		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-	-		
44	Miscellaneous Amortization (425)		-	-		
45	Donations (426.1)	340	167,380	150,558		
46	Life Insurance (426.2)		-	-		
47	Penalties (426.3)		3,337	512		
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		89,201	85,387		
49	Other Deductions (426.5)		310	-		
50	TOTAL Other Inc. Deducions (Total of Lines 41 thru 43)	340	260,228	236,457		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,962	2,604		
53	Income Taxes-Federal (409.2)	262-263	(379)	1,134		
54	Income Taxes-Other (409.2)	292-263	-	-		
55	Provision for Deferred Income Taxes (410.2)	234-235	-	-		
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	-	-		
57	Investment Tax Credit Adj.-Net (411.5)		-	-		
58	(Less) Investment Tax Credits (420)		-	-		
59	TOTAL Taxes on Other Inc.& Deductions(Total of 52 thru 58)		2,583	3,738		
60	Net Other Inc. & Deductions (Total of lines 41, 50, 59)		421,647	2,694		
61	**INTEREST CHARGES**					
62	Interest on Long-Term Debt (427)		7,102,990	5,795,908		
63	Amort. of Debt Disc. and Expense (428)	258-259	127,859	98,517		
64	Amort. of Loss on Reacquired Debt (428.1)		31,654	51,845		
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	-	-		
66	(Less) Amort. of Gain on Reacquired Debt-Credit (429.1)		-	-		
67	Interest on Debt to Associated Companies (430)	340	-	-		
68	Other Interest Expense (431)	340	104,843	854,562		
69	(Less) Allowance for Borrowed Funds Used During Constr.-Credit(432)		(255,584)	(213,372)		
70	Net Interest Charges (Total of lines 62 thru 69)		7,111,762	6,587,460		
71	Income Before Extraord. Items (Total of lines 27, 60, and 70)		8,879,578	11,904,459		
72	**EXTRAORDINARY ITEMS**					
73	Extraordinary Income (434)		-	-		
74	(Less) Extraordinary Deductions (435)		-	-		
75	Net Extraordinary Items (Total of line 73 less line 74)		-	-		
76	Income Taxes - Federal and Other (409.3)	262-263	-	-		
77	Extraord. Items After Taxes (Total of line 75 less line 76)		-	-		
78	Net Income (Total of lines 71 and 77)		8,879,578	11,904,459	-	-

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2014**

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Electric Utilitly Current Year to Date (in dollars) (g)	Electric Utilitly Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
27	-	-	15,569,693	18,489,225	-	-
28						
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	16,772	17,287	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	358,649	198,705	-	-
38	-	-	278,237	9,489	-	-
39	-	-	30,800	17,408	-	-
40	-	-	-	-	-	-
41	-	-	684,458	242,889	-	-
42						
43			-	-		
44			-	-		
45			167,380	150,558		
46				-		
47			3,337	512		
48			89,201	85,387		
49	-	-	310	-	-	-
50	-	-	260,228	236,457	-	-
51						
52	-	-	2,962	2,604	-	-
53	-	-	(379)	1,134	-	-
54	-	-	-	-	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-	-	-	-	-
59	-	-	2,583	3,738	-	-
60	-	-	421,647	2,694	-	-
61						
62	-	-	7,102,990	5,795,908	-	-
63	-	-	127,859	98,517	-	-
64	-	-	31,654	51,845	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	104,843	854,562	-	-
69	-	-	(255,584)	(213,372)	-	-
70	-	-	7,111,762	6,587,460	-	-
71	-	-	8,879,578	11,904,459	-	-
72						
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76				-		
77			-	-		
78	-	-	8,879,578	11,904,459	-	-

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec 31, 2014

Summary of Utility Plant and Accumulated Provisions For Depreciation, Amortization, and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	609,314,724
4	Property under capital leases	
5	Plant purchased or sold	
6	Completed construction not classified	10,825,600
7	Experimental plant unclassified	
8	TOTAL Utility Plant(Total of lines 3 thru 7)	620,140,324
9	Leased to others	
10	Held for future use	
11	Construction work in progress	14,451,001
12	Acquisition adjustments	
13	Total Utility Plant (Total of Lines 8 thru 12)	634,591,325
14	Accumulated Provisions For Depreciation, Amortization & Depletion	(319,642,483)
15	Net Utility Plant (Total of Line 13 less 14)	314,948,842
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(315,453,776)
19	AmortIzation and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	
21	Amortization of Other Utility Plant	(4,188,707)
22	TOTAL In Service (Total of Lines 18 thru 21)	(319,642,483)
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	TOTAL Leased to others (Total of Lines 24 and 25)	-
27	Held for Future Use	
28	Depreciation	
29	Amortization	
30	TOTAL Held for Future Use (Total of Lines 28 and 29)	-
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustments	
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	(319,642,483)

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec 31, 2014**

Summary of Utility Plant and Accumulated Provisions For Depreciation, Amortization, and Depletion (Continued)

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3		609,314,724		
4				
5				
6		10,825,600		
7				
8	-	620,140,324	-	
9				
10				
11		14,451,001		
12				
13	-	634,591,325	-	
14		(319,642,483)		
15	-	314,948,842	-	
16				
17				
18		(315,453,776)		
19				
20				
21		(4,188,707)		
22	-	(319,642,483)	-	
23				
24				
25				
26	-	-	-	
27				
28				
29				
30	-	-	-	
31				
32				
33	-	(319,642,483)	-	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec 31, 2014

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.
4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c).Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d),

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT		
2	301 Organization	114,734	
3	302 Franchises and Consents	138,158	
4	303 Miscellaneous Intangible Plant	17,265,722	3,604,259
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	17,518,614	3,604,259
6	PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands	-	
9	325.2 Producing Leaseholds	-	
10	325.3 Gas Rights	-	
11	325.4 Rights-of-Way	-	
12	325.5 Other Land and Land Rights	-	
13	326 Gas Well Structures	-	
14	327 Field Compressor Station Structures	-	
15	328 Field Measuring and Regulating Station Equipment	-	
16	329 Other Structures	-	
17	330 Producing Gas Wells - Well Construction	-	
18	331 Producing Gas Wells - Well Equipment	-	
19	332 Field Lines	-	
20	333 Field Compressor Station Equipment	-	
21	334 Field Measuring and Regulating Station Equipment	-	
22	335 Drilling and Cleaning Equipment	-	
23	336 Purification Equipment	-	
24	337 Other Equipment	-	
25	338 Unsuccessful Exploration and Development Costs	-	
26	339 Asset Retirement Costs for Natural Gas Production and		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8)	-	-
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights	-	
30	341 Structures and Improvements	-	
31	342 Extraction and Refining Equipment	-	
32	343 Pipe Lines	-	
33	344 Extracted Products Storage Equipment	-	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec 31, 2014

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (continued)

including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1				
2		380		115,114
3				138,158
4		57,209		20,927,190
5	-	57,589	-	21,180,462
6				
7				
8				-
9				-
10				-
11				-
12				-
13				-
14				-
15				-
16				-
17				-
18				-
19				-
20				-
21				-
22				-
23				-
24				-
25				-
26				-
27	-	-	-	-
28				
29				-
30				-
31				-
32				-
33				-

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2014**

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
34	345	Compressor Equipment	-	-
35	346	Gas Measuring and Regulating Equipment	-	-
36	347	Other Equipment	-	-
37	348	Asset Retirement Costs for Products Extraction Plant	-	-
38		TOTAL Products Extraction Plant (Total Lines 29 thru 37)	-	-
39		TOTAL Natural Gas Production Plant (Total line 27 and 38)	-	-
40	Manufactured Gas Production Plant (Submit Supplementary		-	-
41		TOTAL Production Plant (Total of lines 39 and 40)	-	-
42	NATURAL GAS STORAGE AND PROCESSING PLANT			
43	Underground Storage Plant			
44	350.1	Land	-	-
45	350.2	Rights-of-Way	-	-
46	351	Structures and Improvements	-	-
47	352	Well	-	-
48	352.1	Storage Leaseholds and Rights	-	-
49	352.2	Reservoirs	-	-
50	352.3	Non-recoverable Natural Gas	-	-
51	353	Lines	-	-
52	354	Compressor Station Equipment	-	-
53	355	Other Equipment	-	-
54	356	Purification Equipment	-	-
55	357	Other Equipment	-	-
56	358	Asset Retirement Costs for Underground Storage Plant	-	-
57		TOTAL Underground Storage Plant (enter total of lines 44 thru 56)	-	-
58	Other Storage Plant			
59	360	Land and Land Rights	-	-
60	361	Structures and Improvements	-	-
61	362	Gas Holders	-	-
62	363	Purification Equipment	-	-
63	363.1	Liquefaction Equipment	-	-
64	363.2	Vaporizing Equipment	-	-
65	363.3	Compressor Equipment	-	-
66	363.4	Measuring and Regulating Equipment	-	-
67	363.5	Other Equipment	-	-
68	363.6	Asset Retirement Costs for Other Storage Plant	-	-
69		TOTAL Other Storage Plant (Enter Total of lines 58-68)	-	-
70	Base Load Liquefied Nat. Gas Terminating & Processing Plant			
71	364.1	Land and Land Rights	-	-
72	364.2	Structures and Improvements	-	-
73	364.3	LNG Processing Terminal Equipment	-	-
74	364.4	LNG Transportation Equipment	-	-
75	364.5	Measuring and Regulating Equipment	-	-
76	364.6	Compressor Station Equipment	-	-
77	364.7	Communications Equipment	-	-
78	364.8	Other Equipment	-	-
79	364.9	Asset Retirement Costs for Base Load Liquefied Nat Gas	-	-
80	TOTAL Base Load Liq. Nat. Gas Terminating & Processing		-	-

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending Dec 31, 2014

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (continued)

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
34	-	-	-	-
35	-	-	-	-
36	-	-	-	-
37	-	-	-	-
38	-	-	-	-
39	-	-	-	-
40	-	-	-	-
41	-	-	-	-
42	[redacted]			
43				
44	-	-	-	-
45	-	-	-	-
46	-	-	-	-
47	-	-	-	-
48	-	-	-	-
49	-	-	-	-
50	-	-	-	-
51	-	-	-	-
52	-	-	-	-
53	-	-	-	-
54	-	-	-	-
55	-	-	-	-
56	-	-	-	-
57	-	-	-	-
58	[redacted]			
59	-	-	-	-
60	-	-	-	-
61	-	-	-	-
62	-	-	-	-
63	-	-	-	-
64	-	-	-	-
65	-	-	-	-
66	-	-	-	-
67	-	-	-	-
68	-	-	-	-
69	-	-	-	-
70	[redacted]			
71	-	-	-	-
72	-	-	-	-
73	-	-	-	-
74	-	-	-	-
75	-	-	-	-
76	-	-	-	-
77	-	-	-	-
78	-	-	-	-
79	-	-	-	-
80	-	-	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec 31, 2014

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
81		TOTAL Nat'l Gas Storage and Processing Plant (Total of 57,	-	-
82	TRANSMISSION PLANT			
83	365.1	Land and land rights	211,405	
84	365.2	Rights-of-way	1,018,396	
85	366	Structures and improvements	-	
86	367	Mains	9,985,354	
87	368	Compressor station equipment	-	
88	369	Measuring and regulating station equipment	156,139	
89	370	Communication equipment	-	
90	371	Other equipment	-	
91	372	Asset Retirement Costs for Transmission Plant	-	
92		TOTAL Transmission Plant (Total lines 83 thru 91)	11,371,294	-
93	DISTRIBUTION PLANT			
94	374	Land and land rights	2,242,319	
95	375	Structures and improvements	995,783	
96	376	Mains	287,714,765	11,211,199
97	377	Compressor station equipment	2,000,731	
98	378	Measuring and regulating equipment - General	13,767,175	2,105,517
99	379	Measuring and regulating equipment - City gate	-	
100	380	Services	146,887,820	4,588,845
101	381	Meters	36,104,431	1,598,008
102	382	Meter installations	21,966,113	153,444
103	383	House regulators	7,468,921	258,617
104	384	House regulator installations	-	
105	385	Industrial measuring and regulating station equipment	7,358,101	231,606
106	386	Other property on customers' premises	-	
107	387	Other equipment	-	
108	388	Retirement Costs for Distribution Plant	44,426	
109		TOTAL Distribution Plant (Enter total of lines 94 thru 108)	526,550,585	20,147,236
110	GENERAL PLANT			
111	389	Land and land rights	1,778,485	
112	390	Structures and improvements	12,891,845	213,337
113	391	Office furniture and Equipment	5,399,356	377,416
114	392	Transportation equipment	8,949,880	1,039,412
115	393	Stores equipment	45,197	
116	394	Tools, shop and garage equipment	4,481,439	473,061
117	395	Laboratory equipment	111,341	
118	396	Power operated equipment	2,201,808	1,295,405
119	397	Communication equipment	3,921,525	154,501
120	398	Miscellaneous equipment	22,286	22,983
121		Subtotal (Total of lines 111 thru 120)	39,803,162	3,576,115
122	399	Other Tangible Property		
123	399.1	Asset Retirement Costs for General Plant	-	-
124		TOTAL General Plant (Total lines 121, 122, and 123)	39,803,162	3,576,115
125		TOTAL (Accounts 101 and 106)	595,243,655	27,327,610
126		Gas plant purchased (See Instruction 8)	.	-
127		(Less) Gas plant sold (See Instruction 8)	-	-
128		Experimental gas plant unclassified	-	-
129		TOTAL Gas Plant In Service (Enter Total of lines 125 thru 128)	595,243,655	27,327,610

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec 31, 2014

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (continued)

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
81	-	-	-	-
82	[redacted]			
83				211,405
84				1,018,396
85				-
86				9,985,354
87				-
88				156,139
89				-
90				-
91				-
92	-	-	-	11,371,294
93	[redacted]			
94		237		2,242,556
95		998		996,781
96	337,789			298,588,175
97				2,000,731
98	12,324			15,860,368
99				-
100	183,882			151,292,783
101		(33,573)		37,668,866
102	7,287			22,112,270
103	72,496	(6,946)		7,648,096
104				-
105	6,433			7,583,274
106				-
107				-
108				44,426
109	620,211	(39,284)	-	546,038,326
110	[redacted]			
111		1,609		1,780,094
112		14,218		13,119,400
113	499,092	16,141		5,293,821
114	699,445	3,627		9,293,474
115	(11,149)	108		56,454
116	(53,228)	3,327		5,011,055
117	8,997	272		102,616
118	741,033	114		2,756,294
119	(3,081)	2,009		4,081,116
120	(10,576)	73		55,918
121	1,870,533	41,498	-	41,550,242
122				
123	-	-	-	-
124	1,870,533	41,498	-	41,550,242
125	2,490,744	59,803	-	620,140,324
126	[redacted]	-	-	-
127	-	-	-	-
128	-	-	-	-
129	2,490,744	59,803	-	620,140,324

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2014**

GAS PROPERTY AND CAPACITY LEASED TO OTHERS

1. For all leases in which the average lease income over the initial term of the lease exceeds $500,000, provide in column (c) a description of each facility or leased capacity that is classified as gas plant in service, and is leased to others for gas operations.
2. In column (d) provide the lease payments received from others.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments For Current Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	TOTAL -			

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2014**

GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $1,000,000 or more. Group other items of property held for future use.

2. For property having an original cost of $1,000,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	**TOTAL -**			

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (Mo, Da, Yr)	YEAR OF REPORT Dec. 31, 2014

CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year or project in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under caption Research, Development, and Demonstration (see Acct. 107 of the Uniform System of Accounts).
3. Minor projects (less than $500,000) may be grouped.

Line No	Description of Project (a)	Construction Work in Progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	MN - HANFORD DOE PRELIMINARY	4,001,142	
2	SOUTHRIDGE GATE STATION - NWP	1,339,384	
3	BELLINGHAM GATE UPGRADE NWP CO	1,011,242	
4	Bellingham 1 Gate Station Upgr	906,166	
5	Ug Gms Purch Sw - Cng Direct	888,794	
6	6" HP REINFORCEMENT COLLEGE PL	757,973	
7	RF; 12" HP, SHELTON	710,979	
8	IVR-WEB IMPLEMENTATIION - DRCT	542,987	
9	Gl Essentials Software - Direc	532,815	
10			
11			
12			
13	Minor distribution system/general plant projects each under $500,000	3,759,519	
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45	**TOTAL -**	**14,451,001**	-

BLANK PAGE

[Next page is 217]

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

Non-Traditional Rate Treatment Afforded New Projects

1. The Commission's Certificate Policy Statement provides a threshold requirement for existing pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. See Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC P61,227 (1999); order clarifying policy, 90 FERC P61,128 (2000); order clarifying policy, 92 FERC P61,094 (2000) (Policy Statement). In column a, list the name of the facility granted non-traditional rate treatment.
2. In column b, list the CP Docket Number where the Commission authorized the facility.
3. In column c, indicate the type of rate treatment approved by the Commission (e.g. incremental, at risk)
4. In column d, list the amount in Account 101, Gas Plant in Service, associated with the facility.
5. In column e, list the amount in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant, associated with the facility.

Line No	Name of Facility (a)	CP Docket No. (b)	Type of Rate Treatment (c)	Gas Plant in Service (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
	Total			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

Non-Traditional Rate Treatment Afforded New Projects (continued)

6. In column f, list the amount in Account 190, Accumulated Deferred Income Tax; Account 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account 282, Accumulated Deferred Income Taxes – Other Property; Account 283, Accumulated Deferred Income Taxes – Other, associated with the facility.
7. In column g, report the total amount included in the gas operations expense accounts during the year related to the facility (Account 401, Operation Expense).
8. In column h, report the total amount included in the gas maintenance expense accounts during the year related to the facility.
9. In column i, report the amount of depreciation expense accrued on the facility during the year.
10. In column j, list any other expenses(including taxes) allocated to the facility.
11. In column k, report the incremental revenues associated with the facility.
12. Identify the volumes received and used for any incremental project that has a separate fuel rate for that project.
13. Provide the total amounts for each column.

Line No	Accumulated Depreciation (e)	Accumulated Deferred Income Taxes (f)	Operating Expense (g)	Maintenance Expense (h)	Depreciation Expense (i)	Other Expenses (including taxes) (j)	Incremental Revenues (k)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (Mo, Da, Yr)	YEAR OF REPORT Dec 31, 2014

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead, explain: (a) the nature and extent of work, etc., that the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

1. Engineering & Supervision and General & Administrative overhead:

Engineer & Supervision (ES) overhead consists of employees' time in preparation of work orders, mapping, determining feasibility, and other Engineering/construction based supervisory costs related to new construction which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

General & Administrative (GA) overhead consists of employees' time in processing A/P, A/R, receiving orders,and other administrative functions which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

Both ES & GA (ES/GA) are accumulated in pools from which a portion is allocated each month. The allocation is based on a rate determined by the Fixed Assets Analyst and approved by the Manager of General & Asset Accounting which is then applied to the current month activity for all applicable work orders to determine how much should be transferred from the ES/GA pools to the affected work orders. This is accomplished via a system (PowerPant) batch operation. An applicable work order is one that 1) is capital installation/purchase, and not a preliminary survey or investigative in nature. Note that purchase projects only receive GA overhead, not ES. Construction projects receive both.

2. ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION (AFUDC):
The formula on page 218a is used.

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION ☐ A	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec 31, 2014

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.
2. Identify, in a footnote, the specific entity used as the source for the capital structure figures.
3. Indicate, in a footnote, if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No		Title (a)		Amount (b)	Capitalization Ratio (%) (c)		Cost Rate Percentage (d)
	(1)	Average Short-Term Debt	S	5,143,621			
	(2)	Short-Term Interest Rate				s	3.05%
	(3)	Long-Term Debt	D	161,786,857	49.5%	d	5.72%
	(4)	Preferred Stock	P	0		p	10.00%
	(5)	Common Equity	C	164,988,681	50.5%	c	10.00%
	(6)	Total Capitalization		326,775,538	100.0%		
	(7)	Average Construction Work In Progress	W	$ 14,267,376			

2. Gross Rate for Borrowed Funds	s (S/W) + d[(D/(D+P+C)) (1 - S/W))]	2.91%
3. Rate for Other Funds	[1 - (S/W)] [p(P/(D+P+C)) + c (C/(D+P+C))]	3.23%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 2.87%

b. Rate for Other Funds - 3.19%

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 10, column (c), and that reported for gas plant in service, pages 204-209, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classification, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequences, e.g., 7.01, 7.02, etc.

Section A. Balances and Changes During the Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In-Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	(301,843,195)	(301,843,195)	-	-
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(15,261,616)	(15,261,616)		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-			
5	(413) Expense of Gas Plant Leased to Others	-			
6	Transportation Expenses - Clearing	(812,269)	(812,269)		
7	Other Clearing Accounts	-			
8	Other Clearing (specify) (footnote details):	-			
	ARO Assets	(641)	(641)		
9		-			
10	TOTAL Depreciation Provisions for the Year (Total of lines 3 thru 8)	(16,074,526)	(16,074,526)	-	-
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	2,490,744	2,490,744		
13	Cost of Removal	940,585	940,585		
14	Salvage (Credit)	(922,898)	(922,898)		
15	TOTAL Net Charges for Plant Retired (Total of lines 12 thru 14)	2,508,431	2,508,431	-	-
16	Other Debit or Credit Items (Describe) (footnote datails):				
	Increase/Decrease in RWIP	(35,169)	(35,169)		
	Other Debits/Credits	(9,317)	(9,317)		
17		-			
18	Book Cost of Asset Retirement Costs				
19	BALANCE End of Year (Total of lines 1, 10,15,16 and 18)	(315,453,776)	(315,453,776)	-	-
	Section B. Balances at End of Year According to Functional Classifications				
21	Production - Manufactured Gas	-			
22	Production and Gathering - Natural Gas	-			
23	Products Extraction - Natural Gas	-			
24	Underground Gas Storage	-			
25	Other Storage Plant	-			
26	Base Load LNG Terminalling & Processing Plant	-			
27	Transmission	(8,125,222)	(8,125,222)		
28	Distribution	(287,736,553)	(287,736,553)		
29	General	(19,593,912)	(19,593,912)		
	Intangible Plant	(138,158)	(138,158)		
	Retirement work-in-progress	140,069	140,069		
30	TOTAL (Enter Total of lines 21 thru 31)	(315,453,776)	(315,453,776)	-	-

Line 16 Other Debit or Credit - Due to transfer of assets, and related depreciation reserve, between state jurisdictions

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2014

GAS STORED (Account 117.1, 117.2, 117.3, 117.4, 164.1, 164.2 and 164.3)

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.
2. Report in column (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.
3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e., fixed asset method or inventory method).

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance, beginning of year					Not allocated	Not allocated		Not allocated
2	Gas delivered to storage								
3	(contract account)					-	-		0
4	Gas withdrawn from storage								
5	(contra account)					-	-		0
6	Other debits or credits								
7	(pipeline imbalance)					-	-		0
8									
9									
10	Balance, end of year					Not allocated	Not allocated		Not allocated
11									
12	Therms, Mcf					Not allocated	Not allocated		Not allocated
13									
14	Amount per therm								
15	Amount per Mcf								
16									
17	Dth								
18	Amount Per Dth								
19									
20									
21									
22									
23									
24									
25	State basis of segregation of inventory between current and noncurrent portions:								

.

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant & Regulatory Study Costs (Acct 182.2)

Prepayments (Acct 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payments (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	Not Allocated
2	Prepaid Rents	Not Allocated
3	Prepaid Taxes	Not Allocated
3a	Prepaid Pension	-
3b	Prepaid Executive Supplemental Retirement	-
4	Prepaid Interest	-
5	Miscellaneous Prepayments	Not Allocated
6	**TOTAL -**	**-**

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant & Regulatory Study Costs (Acct 182.2) (Continued)

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr to mo. Yr)]. Add rows as necessary to report all data. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Losses Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
7							
8							
9	none						
10							
11							
12							
13							
14							
15	**TOTAL -**						

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant & Regulatory Study Costs (Acct 182.2) (Continued)

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (Account 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the drscription of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)]. Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used in extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Costs Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
16							
17							
18	none						
19							
20							
21							
22							
23							
24							
25							
26	**Total**						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2014

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory ciation where authoriztion for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1							
2							
3							
4	Miscellaneous	-					-
5							
6							
7	Asset Retirement Obligation	539,036	35,710		-	-	574,746
8	(WA regulatory asset)						
9							
10	FAS 158 Regulatory Asset	35,732,423	16,613,526		-	-	52,345,949
11	Total system asset						
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40	**Total system asset**	**36,271,459**	**16,649,236**		**-**	**-**	**52,920,695**

Name of Respondant	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

Miscellaneous Deferred Debits (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred deibt being amortized, show period of amortization in column (a).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	WA Conservation Programs	3,555,548	4,851,120	4800-4813	5,508,865	2,897,803
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant Remediation	14,071,601	1,328,214		375	15,399,440
5						
6	WA Gas Management Sharing Margin	(106,484)	23,670	4800-4813, 4890	3,430	(86,244)
7	(amortization period 11/10-present)					
8						
9	WA Over-refunded Temporary Revenue Credit	(3,008)	3,552		18,784	(18,240)
10						
11	WA Core Gas Supply Hedging (current & noncurrent)	0	-		-	0
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	**Total**	**17,517,657**	**6,206,556**		**5,531,454**	**18,192,759**

BLANK PAGE

[Next page is 234]

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could include in the fevelopment of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric	-		
3	Gas	20,926,644	2,086,789	-
4		-		
5	Total (Total of Lines 2 thru 4)	20,926,644	2,086,789	-
6	Other (Specify)	-		
7	TOTAL Account 190 (Lines 5 thru 6)	20,926,644	2,086,789	-
8	Classification of TOTAL			
9	Federal Income Tax	20,039,172	2,000,055	-
10	State Income Tax	887,472	86,734	-
11	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	see below	1,373,438	-
	Federal Income Tax - Oregon	see below	626,617	-
	State Income Tax - Oregon	887,472	86,734	-

The federal balance in account 190 is allocated to Washington & Oregon on the basis of the Company's 3-factor formula which is used for the allocation of corporate level operating & maintenance expenses and interstate plant as follows:

	Beginning of Year	End of Year
Federal Income Tax related account Balance	20,039,172	21,739,456
Balance to be allocated	20,039,172	21,739,456
Washington allocation factor	75.45%	75.70%
Washington Allocated balance	15,119,555	16,456,768
Oregon allocation factor	24.55%	24.30%
Oregon Allocated balance	4,919,617	5,282,688

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

Line No.	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Ajustments Debits Account No. (g)	Ajustments Debits Amount (h)	Ajustments Credits Account No. (I)	Ajustments Credits Amount (j)	Balance at End of Year (k)
1							
2							-
3	-	-	Regulatory accounts related to FAS 158 and OR rate change adjustments	(3,863,519)		-	22,703,374
4							-
5	-	-		(3,863,519)		-	22,703,374
6							-
7	-	-		(3,863,519)		-	22,703,374
8							
9	-	-		(3,700,339)		-	21,739,456
10	-	-		(163,180)			963,918
11	-	-		-		-	-
	-	-		(2,541,023)		-	see below
	-	-		(1,159,316)		-	see below
	-	-		(163,180)		-	963,918

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal Income Tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconcilling amount.
2. If the utility is a member of a group that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	12,035,057
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	CIAC	2,757,224
12	Tax Gain (loss) on disposal of assets:	
13	Pre-1981 assets	(224)
14	Post-1980 assets	339,239
8	Broken Meter interest charges	-
9	TOTAL	3,096,239
10	Deductions Recorded on Books Not Deducted for Return	
11	Tax Expense	7,050,183
12	Depreciation provision	
13	Pre-1981	(3,560)
14	Post-1980	22,851,843
15	Vacation Accrual - current year	1,390,916
16	Bad Debt Expense	1,391,878
17	STIP accrual - addback	980,749
18	SFAS No.87 accrual-SERP/SISP expense	760,449
20	SFAS No.87 pension plan accrual	358,723
19	Retiree Medical Accrual	115,537
21	Amort of loss on reacquired debt (4281)	40,971
23	Permanent diff's	
24	50 % of business meals & entertainment	176,141
25	Lobbying (5912.4264)	122,435
26	Interest Expense	65,258
27	Penalties (5984)	4,408
28	TOTAL	35,305,931
29	Income Recorded on Books Not Included in Return	
30	Interest capitalized adj (IRS>books)	(241,451)
22	AFUDC Equity	(67,145)
31	TOTAL	(308,596)
32	Adjusted Net Income to carry forward to page 261A, line 1	50,128,631
33		

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES (cont.)

Line	Description			Amount
1	Adjusted Net Income carried forward from page 261, line 34			50,128,631
2	Deductions on Return Not Charged Against Book Income			
3	Depreciation & amortization of plant			-
4	Pre-1981			(220,224)
5	Post-1980			(37,342,012)
6	CC&B Deduction			(1,566,582)
6	Repairs Deduction			(3,878,645)
7	Deferred Gas Costs			(4,940,456)
8	Funding of pension plan			(1,435,385)
9	Vacation accrual - prior year			(1,304,023)
10	Bad debts written off			(1,399,974)
11	Bremerton MGP expenses			(840,407)
6	Eugene MGP expenses			(77,489)
15	Retiree Medical payments			(471,417)
16	SERP - benefit pymts out of plan			(501,615)
17	Charitable Contributions (5981.4261)			(250,153)
18	Customer Advances - 2520.000 to 2520.2991			(1,180,780)
19	STIP accrual - prior year			(747,218)
7	263A Adjustment - UNICAP			(14,949)
20	Permanent diff's			-
21	401K Dividends (MDUR)			(96,807)
22	SERP-perm difference piece			(448,246)
23	Oregon State Income Tax			107,060
24	TOTAL			(56,609,322)
25	Federal Tax Net Income			**(6,480,691)**
26	Show Computation of Tax:			
27	Rate			35%
28	Estimated Tax Return Federal Income Tax			**(2,268,242)**
29	Adjustments:			
30	Difference between 12/31/13 accrual and tax return			(4,998,359)
31	Provision for Current Federal Income Tax			**(7,266,601)**
32	Allocated to:	409.1	409.2	Total
33	Washington	(4,989,631)	(379)	(4,990,010)
34	Oregon	(2,276,469)	(122)	(2,276,591)
35	Total	**(7,266,100)**	**(501)**	**(7,266,601)**

Name of Respondant **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report **Dec. 31, 2014**

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	WA Deferred Gas Costs	(3,982,995)	805.1	34,571,292	30,008,130	(8,546,157)
2	(amortization period 11/10-present)					
3						
4						
5						
6	SGL Deposit	Unallocated	134 / 228.4			Unallocated
7	Customer Unclaimed Credits	Unallocated	131			Unallocated
8	MDUR Interco NC Payable - FAS 158	Unallocated	228.3/182			Unallocated
9	Pension Contribution	Unallocated	various			Unallocated
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40	**Total**	**(3,982,995)**		**34,571,292**	**30,008,130**	**(8,546,157)**

BLANK PAGE

[Next page is 274]

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric			
3	Gas	(84,106,817)	(11,635,316)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(84,106,817)	(11,635,316)	-
6				
7	Total (Account 282) Lines 5 thru 6	(84,106,817)	(11,635,316)	-
8	Classification of Totals			
9	Federal Income Tax	(81,315,722)	(11,100,648)	-
10	State Income Tax	(2,791,095)	(534,668)	-
11	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See Below	(7,622,815)
Federal Income Tax - Oregon	See Below	(3,477,833)
State Income Tax - Oregon	(2,791,095)	(534,668)

The federal balance in account 282 relating to utility plant for ratemaking is allocated to Washington & Oregon on the basis of the Company's Rate Base ratio, the remaining portion is allocated on the basis of the Company's ratio of utility plant in each state as follows:

	Beginning of Year	End of Year
Federal Income Tax Acct Balance Relating to utility plant for ratemaking	(84,824,483)	(95,928,135)
Washington allocation factor	76.48%	77.26%
Washington Allocated balance relating to utility plant for ratemaking	(64,873,765)	(74,114,077)
Oregon allocation factor	23.52%	22.74%
Oregon Allocated balance relating to utility plant for ratemaking	(19,950,718)	(21,814,058)
Remaining balance to be allocated on Utility Plant	3,508,761	3,172,469
Washington allocation factor	77.43%	77.66%
Washington allocation	2,716,834	2,463,739
Plus Washington Allocation of utility plant for ratemaking related balance	(64,873,765)	(74,114,077)
Total Washington Allocated Balance	(62,156,931)	(71,650,338)

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amonts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (I)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	[redacted]						
2							
3	-	-	182.3 & 254	281,562	182.3 & 254	677,561	(96,138,132)
4							
5	-	-		281,562		677,561	(96,138,132)
6							
7	-	-		281,562		677,561	(96,138,132)
8	[redacted]						
9	-	-	254	253,818	254	593,114	(92,755,666)
10	-	-	182.3	27,744	182.3	84,447	(3,382,466)
11	-	-		-		-	-
				174,297		407,291	See Below
				79,521		185,823	See Below
	-	-		27,744		84,447	(3,382,466)

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

ACCUMULATED DEFERRED INCOME TAXES-Other (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(28,196,051)	(1,060,709)	-
4		-		
5	Total (Total of Lines 2 thru 4)	(28,196,051)	(1,060,709)	-
6		-		
7				
8	Total Account 283 (Total of lines 5 thru 8)	(28,196,051)	(1,060,709)	-
9	Classification of TOTAL			
10	Federal Income Tax	(26,635,990)	(1,006,406)	-
11	State Income Tax	(1,560,061)	(54,303)	-
12	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See Below	(691,099)	-
Federal Income Tax - Oregon	See Below	(315,307)	-
State Income Tax - Oregon	(1,560,061)	(54,303)	-

The federal balance in account 283 relating to debt refinancing costs is allocated to Washington & Oregon on the basis of the Company's Rate Base ratio; the remaining portion is allocated on the basis of the 3-factor formula which is used for the allocation of corporate level operating & maintenance expenses and interstate plant. The allocation in each state is as follows:

	Beginning of Year	End of Year
Federal Income Tax Acct Balance Relating to Debt Refinancing	(327,154)	(327,154)
Washington allocation factor	76.48%	77.26%
Washington Allocated balance relating to Debt Refinancing	(250,207)	(252,759)
Oregon allocation factor	23.52%	22.74%
Oregon Allocated balance relating to Debt Refinancing	(76,947)	(74,395)
Remaining balance to be allocated on 3-factor	(26,308,836)	(31,020,074)
Washington allocation factor	75.45%	75.70%
Washington allocation	(19,850,017)	(23,482,196)
Plus Washington Allocation of Debt refinancing related balance	(250,207)	(252,759)
Total Washington Allocated Balance	(20,100,224)	(23,734,955)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2014

ACCUMULATED DEFERRED INCOME TAXES-Other (Account 283) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (I)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							-
3	-	-	Regulatory accounts related to deferred tax effect of OR State Tax Rate increase	32,396	Regulatory accounts related to deferred tax effect of OR State Tax Rate increase	3,868,013	(33,092,377)
4							-
5	-	-		32,396		3,868,013	(33,092,377)
6							-
7							-
8	-	-		32,396		3,868,013	(33,092,377)
9							
10	-	-		-		3,704,832	(31,347,228)
11	-	-		32,396		163,181	(1,745,149)
12	-	-		-		-	-
	-	-		-		2,544,108	See Below
	-	-		-		1,160,724	See Below
	-	-		32,396		163,181	(1,745,149)

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

GAS OPERATING REVENUES

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.

Line No.		Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (b)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480	Residential Sales	none	none	none	none
2	481	Commerical and Industrial Sales				
3	482	Other Sales to Public Authorites				
4	483	Sales for Resale				
5	484	Interdepartmental Sales				
6	485	Intracompany Transfers				
7	487	Forfeited Discounts				
8	488	Miscellaneous Service Revenues				
9	489.1	Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2	Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3	Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4	Revenues from Storing Gas of Others				
13	490	Sales of Prod. Ext. from Natural Gas				
14	491	Revenues from Natural Gas Proc. By Others				
15	492	Incidental Gasoline and Oil Sales				
16	493	Rent from Gas Property				
17	494	Interdepartmental Rents				
18	495	Other Gas Revenues				
19		Subtotal:				
20	496	(Less) Provision for Rate Refunds				
21		TOTAL:				

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

GAS OPERATING REVENUES (continued)

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	$ 128,385,744	$ 117,078,024	$ 128,385,744	$ 117,078,024	11,106,976	11,868,635
2	$ 88,445,285	$ 75,444,061	$ 88,445,285	$ 75,444,061	10,493,258	10,531,287
3						
4						
5						
6						
7						
8	$ 945,352	$ 1,106,379	$ 945,352	$ 1,106,379		
9						
10						
11	$ 19,865,944	$ 19,477,932	$ 19,865,944	$ 19,477,932	73,308,516	75,482,380
12						
13						
14						
15						
16	$ 100	$ 1,000	$ 100	$ 1,000		
17						
18	$ 297,562	$ 234,013	$ 297,562	$ 234,013		
19	**$ 237,939,987**	**$ 213,341,409**	**$ 237,939,987**	**$ 213,341,409**		
20						
21	**$ 237,939,987**	**$ 213,341,409**	**$ 237,939,987**	**$ 213,341,409**		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH GATHERING FACILITIES (ACCOUNT 489.1)

1 Report revenues and Dth of gas delivered through gathering facilities by zone of receipt (i.e. state in which gas enters respondent's system).
2 Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.

Line No.	Rate Schedule and Zone of Receipt (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report **Dec. 31, 2014**

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH GATHERING FACILITIES (continued)

3 Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e).
4 Delivered Dth of gas must not be adjusted for discounting.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH TRANSMISSION FACILITIES (ACCOUNT 489.2)

1. Report revenues and Dth of gas delivered by Zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, provide totals by rate schedule.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges for transportation and hub services less revenues reflected in columns (b) through (e).

Line No.	Zone of Delivery, Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH TRANSMISSION FACILITIES (CONTINUED)

4. Delivered Dth of gas must not be adjusted for discounting.
5. Each incremental rate schedule and each individually certificated rate schedule must be separately reported.
6. Where transportation services are bundled with storage services, report total revenues but only transportation Dth.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

REVENUES FROM STORING GAS OF OTHERS (ACCOUNT 489.4)

1. Report revenues and Dth of gas withdrawn from storage by Rate Schedule and in total.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other revenues in columns (f) and (g) include reservation charges, deliverability charges, injection and withdrawal charges, less revenues reflected in columns (b) through (e).

Line No.	Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

REVENUES FROM STORING GAS OF OTHERS (Account 489.4)

4. Dth of gas withdrawn from storage must not be adjusted for discounting.
5. Where transportation services are bundled with storage services, report only Dth withdrawn from storage.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

OTHER GAS REVENUES (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electicity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tarriff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other Revenuee (Specify):	
12	Miscellaneous Revenues	$ 221,974
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**TOTAL**	**$ 221,974**

BLANK PAGE

[Next page is 317]

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)	0	0
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	0	0
8	751 Production Maps and Records	0	0
9	752 Gas Wells Expenses	0	0
10	753 Field Lines Expenses	0	0
11	754 Field Compressor Station Expenses	0	0
12	755 Field Compressor Station Fuel and Power	0	0
13	756 Field Measuring and Regulating Station Expenses	0	0
14	757 Purification Expenses	0	0
15	758 Gas Well Royalties	0	0
16	759 Other Expenses	0	0
17	760 Rents	0	0
18	TOTAL Operation (Total of lines 7 thru 17)	0	0
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	0
21	762 Maintenance of Structures and Improvements	0	0
22	763 Maintenance of Producing Gas Wells	0	0
23	764 Maintenance of Field Lines	0	0
24	765 Maintenance of Field Compressor Station Equipment	0	0
25	766 Maintenance of Field Measuring and Regulating Station Equipment	0	0
26	767 Maintenance of Purification Equipment	0	0
27	768 Maintenance of Drilling and Cleaning Equipment	0	0
28	769 Maintenance of Other Equipment	0	0
29	TOTAL Maintenance (Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production & Gathering (Total of lines 18 and 29)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchases for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility - Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Total of lines 33 thru 46)	0	0
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Reg. Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration & Development (Total of lines 61 thru 64)	0	0
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	0
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
70	801 Natural Gas Field Line Purchases	0	0
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
72	803 Natural Gas Transmission Line Purchases	0	0
73	804 Natural Gas City Gate Purchases	142,457,180	135,193,143
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchased Gas Cost Adjustments	7,108,817	21,109,831
77	TOTAL Purchased Gas (Total of lines 68 to 76)	135,348,363	114,083,312
78	806 Exchange Gas	0	0
79	Purchased Gas Expenses		
80	807.1 Well Expenses - Purchased Gas	0	0
81	807.2 Operation of Purchased Gas Measuring Stations	0	0
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	0
83	807.4 Purchased Gas Calculations Expenses	0	0
84	807.5 Other Purchased Gas Expenses	0	0
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
86	808.1 Gas Withdrawn from Storage - Debit	5,407,240	3,792,948
87	(Less) 808.2 Gas Delivered to Storage - Credit	4,208,220	4,048,172
88	809.1 Withdrawals of Liquefied Natural Gas for Processing - Debit	0	0
89	(Less) 809.2 Deliveries of Natural Gas for Processing - Credit	0	0
90	Gas Used in Utility Operations - Credit		
91	810 Gas Used for Compressor Station Fuel - Credit	0	0
92	811 Gas Used for Products Extraction - Credit	0	0
93	812 Gas Used for Other Utility Operations - Credit	46,245	44,687
94	TOTAL Gas Used in Utility Operations - Credit (Total of lines 91 thru 93)	46,245	44,687
95	813 Other Gas Supply Expenses	312,168	282,213
96	TOTAL Other Gas Supply Exp (Total of lines 77, 78, 85, 86 thru 89, 94, 95)	136,813,306	114,065,614
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65 and 96)	136,813,306	114,065,614
98	2. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Total of lines 101 thru 113)	0	0

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	TOTAL Maintenance (Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulation Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(Less) 845.5 Wharfage Receipts - Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146 and 176)	0	0

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,245,382	1,318,587
205	871 Distribution Load Dispatching	580,901	390,171
206	872 Compressor Station Labor and Expenses	84,951	113,766
207	873 Compressor Station Fuel and Power	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses	3,172,439	3,324,162
209	875 Measuring and Regulating Station Expenses - General	686,339	570,651
210	876 Measuring and Regulating Station Expenses - Industrial	91,225	136,868
211	877 Measuring & Regulating Station Expenses - City Gate Check Station	0	0
212	878 Meter and House Regulator Expenses	1,301,873	1,334,934
213	879 Customer Installations Expenses	968,757	954,135
214	880 Other Expenses	3,576,985	3,402,711
215	881 Rents	74,232	90,911
216	TOTAL Operation (Total of lines 204 thru 215)	11,783,084	11,636,896
217	Maintenance		
218	885 Maintenance Supervision and Engineering	185,206	257,415
219	886 Maintenance of Structures and Improvements	97,374	21,503
220	887 Maintenance of Mains	1,295,005	1,365,635
221	888 Maintenance of Compressor Station Equipment	17,552	9,028
222	889 Maintenance of Measuring and Regulating Station Equipment - General	291,354	368,203
223	890 Maintenance of Meas. and Reg. Station Equipment - Industrial	40,203	32,554
224	891 Maint. of Meas. and Reg. Station Equip. - City Gate Check Station	0	0
225	892 Maintenance of Services	1,407,796	1,124,660
226	893 Maintenance of Meters and House Regulators	1,054,288	951,563
227	894 Maintenance of Other Equipment	217,279	135,613
228	TOTAL Maintenance (Total of lines 218 thru 227)	4,606,057	4,266,174
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	16,389,141	15,903,070
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	19	18,523
233	902 Meter Reading Expenses	498,344	482,615
234	903 Customer Records and Collection Expenses	3,544,044	3,449,046

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	1,107,085	778,477
236	905 Miscellaneous Customer Accounts Expenses	4,275	6,954
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	5,153,767	4,735,615
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	1,033,286	1,076,400
242	909 Informational and Instructional Expenses	24,516	22,294
243	910 Miscellaneous Customer Service and Informational Expenses	269	0
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	1,058,071	1,098,694
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	9,412	6,948
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	9,412	6,948
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	5,181,959	4,753,695
255	921 Office Supplies and Expenses	4,206,289	3,805,828
256	(Less) (922) Administrative Expenses Transferred - Credit	401,444	398,075
257	923 Outside Services Employed	878,005	583,328
258	924 Property Insurance	52,141	59,037
259	925 Injuries and Damages	1,016,647	909,876
260	926 Employee Pensions and Benefits	4,673,857	3,788,515
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	0
263	(Less) (929) Duplicate Charges - Credit	0	0
264	930.1 General Advertising Expenses	42,784	80,189
265	930.2 Miscellaneous General Expenses	421,151	520,115
266	931 Rents	925,407	933,704
267	TOTAL Operation (Totals of lines 254 thru 266)	16,996,796	15,036,212
268	Maintenance		
269	932 Maintenance of General Plant	19,213	80,452
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	17,016,009	15,116,664
271	TOTAL Gas O & M Expenses (Totals of lines 97,177,201,229,237,244,251 and 270)	176,439,706	150,926,605

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

EXCHANGE AND IMBALANCE TRANSACTIONS

1. Report below details by zone and rate schedule concerning the gas quantities and related dollar amount of imbalances associated with system balancing and no-notice service. Also, report certificated natural gas exchange transactions during the year. Provide subtotals for imbalance and no-notice quantities for exchanges. If respondent does not have separate zones, provide totals by rate schedule. Minor exchange transactions (less than 100,000 Dth) may be grouped.

Line No.	Zone/Rate Schedule (a)	Gas Received from Others Amount (b)	Gas Received from Others Dth (c)	Gas Delivered to Others Amount (d)	Gas Delivered to Others Dth (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	TOTAL				

Name of Respondent	This Report is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS USED IN UTILITY OPERATIONS

1 Report below details of credits during the year to Accounts 810, 811, and 812

2 If any natural gas was used by the respondent for which a charge was not made to the appropriate expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used (Dth) (c)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas used for Compressor Station Fuel - Credit					
2	811 Gas used for Products Extraction - Credit					
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, Etc. for Respondent's Gas Processed by Others					
5	812 Gas used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses)					
6						
7		812	10,562	$ 46,245		
8						
9						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	**TOTAL**		**10,562**	**46,245**		

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

TRANSMISSION AND COMPRESSION OF GAS BY OTHERS (Account 858)

1. Report below details concerning gas transported or compressed for respondent by others equalling more than 1,000,000 Dth and amounts of payments for such services during the year. Minor items (less than 1,000,000) Dth may be grouped. Also, include in column (c) amounts paid as transition costs to an upstream pipeline.
2. In column (a) give name of companies, points of delivery and receipt of gas. Designate points of delivery and receipt so that they can be identified readily on a map of respondent's pipeline system.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Company and Description of Service Performed (a)	* (b)	Amount of Payment (in dollar) (c)	Dth of Gas Delivered (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	Total			

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

OTHER GAS SUPPLY EXPENSES (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1	Labor Expenses and applicable overhead charges	262,889
2	Payroll Taxes and benefits	84,170
3	Software Maintenance	15,731
4	Bonuses and Commissions	14,637
5	Commercial Air service	6,065
6	Lodging	5,599
7	Meals & Entertainment	2,334
8	Training materials	966
9	Vehicle Mileage	472
10	Cell Phone	469
11	Office Supplies	368
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	TOTAL	$ 393,700

Name of Respondant	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2014

Miscellaneous General Expenses (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses.

2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items so grouped is shown.

Line No.	Description (a)	Amount (in dollars) (b)
1	Industry association dues.	110,389
2	Experimental and general research expenses.	
	a. Gas Research Institute (GRI)	
	b. Other	
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer	
	agent fees and expenses, and other expenses of servicing outstanding securities of the respondent.	
4		
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex and MDU for CNGC's share of corporate banking fees)	214,700
6		
7	Director's Fees (paid ot MDU for CNGC's share of director's expenses)	92,010
8		
9	Miscellaneous under $250,000 (13 items)	4,052
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	**421,151**

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report **Dec. 31, 2014**

DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT
(Account 403, 404.1, 404.2, 404.3, 405)
(Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups show.

2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a)). Indicate in a footnote the manner in which column (b) balances are

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depetion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant	-			1,644,958
2	Production plant, manufactured plant				
3	Production & gathering plant, natural gas				
4	Products extraction plant				
5	Underground gas storage plant				
6	Other storage plant				
7	Base load LNG terminating and processing				
8	Transmission plant	209,379			
9	Distribution plant	14,323,016			
10	General plant	729,221			
11	Common plant - gas				
12	**TOTAL -**	**15,261,616**		**-**	**1,644,958**

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report **Dec. 31, 2014**

DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT
(Account 403, 404.1, 404.2, 404.3, 405)
(Except Amortization of Acquisition Adjustments) (continued)

obtained. If average balancesare used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of provisions and the plant items to which related.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Amortization of Other Limited-Term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1			1,644,958	Intangible plant
2			-	Production plant, manufactured plant
3			-	Production & gathering plant, natural gas
4			-	Products extraction plant
5			-	Underground gas storage plant
6			-	Other storage plant
7			-	Base load LNG terminating and processing
8			209,379	Transmission plant
9			14,323,016	Distribution plant
10			729,221	General plant
11			-	Common plant - gas
12	**-**	**-**	**16,906,574**	**Total**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec 31, 2014

DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT

(Account 403, 404.1, 404.2, 404.3, 405) (contintued)

4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (Percent) (c)
1	Production and Gathering Plant		
2	Offshore (footnote details)		
3	Onshore (footnote details)		
4	Underground gas storage plant (footnote details)		
5	Transmission Plant		
6	Offshore (footnote details)		
7	Onshore (footnote details)		
8	General Plant (footnote details)		
9	Distribution Plant		
10	Storage Rights		

Notes to Depreciation, Depletion and Amortization of Gas Plant

Depreciation is accrued monthly on the average balance in each plant account using a rate specific to the account. The average balance is the simple average of the balance at the beginning of the month and at the end of the month. The amounts shown below represent the year-end balances of depreciable plant and the weighted average composite rates based on year-end balances in each category.

	Washington		Oregon	
Description (a)	Depreciable Plant Base (Thousands) (b)	Composite Rate (Percent) (c)	Depreciable Plant Base (Thousands) (d)	Composite Rate (Percent) (e)
Intangible plant	21,180		6,975	
Manufactured gas production	0		0	
Transmission plant	11,160	1.88%	5,863	1.92%
Distribution plant	545,674	2.62%	153,948	2.60%
General plant	39,643	3.89%	13,492	3.63%
Total -	617,657	2.87%	180,278	2.85%

Name of Respondant	This Report is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

(a) Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open accounts, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431)-Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)		Amount (b)
1	(a) Miscellaneous Amortization (Account 425)		-
2			
3	*(b) Miscellaneous Income Deductions (Account 426):*		
4	Donations (Account 426.1)		167,380
5			
6	Life Insurance (Account 426.2)		-
7			
8	*Penalties (Account 426.3):*		
9	**Payee**	**Nature**	
10			
11	Various	Miscellaneous	3,337
12			
13			
14	Expenditures for Certain Civic, Political and Related Activities (Account 426.4)		89,201
15			
16	*Other Deductions (426.5):*		
17	**Payee**	**Nature**	
18	Various	Miscellaneous	310
19		**Total Miscellaneous Income Deductions (Account 426)**	**260,228**
20			
21	(c) Interest on Debt to Associated Companies (Account 430)		-
22			
23	*(d) Other Interest Expense (Account 431):*		
24	**Description**	**Interest Rate**	
25	Customer Deposits	Various	1,601
26	Deferral Accounts - WA	FERC Interest Rate	-
27	Interest on Short-Term Debt	Various	106,532
28	Other	Various	54,284
29		**Total Other Interest Expense (Account 431)**	**162,417**
30			
31			
32			
33			
34			

Name of Respondant	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2014**

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.

2. In colums (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commision or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses To Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	**Total**				

Name of Respondant	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

Regulatory Commission Expenses (Account 928)

3. Show in Column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.

4. Identify separately all annual charge adjustments (ACA).

5. List in column (f), (g), and (h) expenses incurred during the year which were charged currently to income, plant, or other accounts.

6. Minor items (less than $250,000) may be grouped.

Line No.	Expenses Incurred During Year Charged Currently to Department (f)	Expenses Incurred During Year Charged Currently to Account No. (g)	Expenses Incurred During Year Charged Currently to Amount (h)	Expenses Incurred During Year Deffered to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deffered in Account 182.3 End of Year (l)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25	**Total**						

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2014

EMPLOYEE PENSIONS AND BENEFITS (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits

Line No.	Expense (a)	Amound (b)
1	Pensions - defined benefit plants	217,230
2	Pensions - other	1,691,659
3	Post-retirement benefits other than pensions (PBOP)	72,190
4	Post-employment beneift plans	336,693
5	Other (Specify)	
6	Medical/Dental	2,090,804
7	Various	269,368
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
	Total	4,677,944

BLANK PAGE

[Next page is 354]

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.company must be assigned to the particular operating function(s) relating to the expenses. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	**Electric**				
2	Operation				
3	Production				
4	Transmission				
5	Distribution				
6	Customer Accounts				
7	Customer Service and Informational				
8	Sales				
9	Administrative and General				
10	TOTAL Operation (Total of lines 3 thru 9)				
11	Maintenance				
12	Production				
13	Transmission				
14	Distribution				
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)				
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)				
19	Transmission (Total of lines 4 and 13)				
20	Distribution (Total of lines 5 and 14)				
21	Customer Accounts (Line 6)				
22	Customer Service and Informational (Line 7)				
23	Sales (Line 8)				
24	Administrative and General (Total of lines 9 and 15)				
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)				
26	**Gas**				
27	Operation				
28	Production-Manufactured Gas				
29	Production-Natural Gas (Including Exploration and Development)				
30	Other Gas Supply				
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution	$ 7,754,988			
34	Customer Accounts	$ 2,928,196			
35	Customer Service and Informational	$ -			
36	Sales	$ -			
37	Administrative and General	$ 4,002,882			
38	TOTAL Operation (Total of lines 28 thru 37)	$ 14,686,066	$ -	$ -	$ 14,686,066
39	Maintenance				
40	Production-Manufactured Gas				
41	Production-Natural Gas (Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission				
45	Distribution	$ 2,619,844			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

DISTRIBUTION OF SALARIES AND WAGES (continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
46	Administrative and General	$ -			
47	TOTAL Maintenance (Total of lines 40 thru 46)	$ 2,619,844	$ -	$ -	$ 2,619,844
48	**Gas (Continued)**				
49	Total Operation and Maintenance				
50	Production-Manufactured Gas (Lines 28 and 40)				
51	Production-Natural Gas - (Including Expl and Dev.) (ll. 29 and 41)				
52	Other Gas Supply (Lines 30 and 42)				
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)	$ -			
55	Distribution (Total of lines 33 and 45)	$ 10,374,832			
56	Custormer Accounts (Total of line 34)	$ 2,928,196			
57	Customer Service and Informational (Total of line 35)	$ -			
58	Sales (Total of line 36)	$ -			
59	Administrative and General (Total of lines 37 and 46)	$ 4,002,882			
60	TOTAL Operation and Maint. (Total of lines 50 thru 59)	$ 17,305,910	$ -	$ -	$ 17,305,910
61	**Other Utility Departments**				
62	Operation and Maintenance				
63	TOTAL All Utility Dept. (Total of lines 25, 60, and 62)	$ 17,305,910	$ -	$ -	$ 17,305,910
64	**Utility Plant**				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	$ 4,596,881			
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	$ 4,596,881	$ -	$ -	$ 4,596,881
70	Plant Removal (By Utiltiy Departments)				
71	Electric Plant				
72	Gas Plant	$ 179,125			
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	$ 179,125			$ 179,125
75	Other Accounts (Specify):				
76					
77	PTO/Incentive/Severance Pay Liabilities	$ 524,112			
78	Miscellaneous Services	$ 1,384			
79					
80	TOTAL Other Accounts	$ 525,496	$ -	$ -	$ 525,496
81	TOTAL SALARIES AND WAGES	$ 22,607,412	$ -	$ -	$ 22,607,412

Name of Respondant	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2014**

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnershp, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political, and Related Activities.

(a)Name of person or organization rendering services.

(b) Total charges for the year.

2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.

3. Total under a description "Total", the total of all of the aforementioned services.

4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	Snelson Companies Inc	3,510,689
2	Northwest Metal Fabrication and Pipe Inc	3,149,550
3	Michels Corporation	1,774,210
4	Northwest Pipeline Corporation	1,013,000
5	MRES Consulting, LTD	976,820
6	Northwest Pipeline GP	616,079
7	Sungard Energy Systems	567,767
8	Day Wireless Systems, Inc.	410,395
9	Potelco, Inc.	404,665
10	Surveys & Analysis, Inc.	380,404
11	Prosource Tech., Inc.	319,912
12	Anchor QEA	304,504
13	Other	5,660,537
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26	**Total**	**19,088,532**

BLANK PAGE

[Next page is 508]

Name of Respondent	This Report is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

COMPRESSOR STATIONS

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, product extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.

2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respndent's title, and percent of ownership if jointly owned.

Line No.	Name of Station and Location (a)	Number of Units at Station (b)	Certified Horsepower for Each Station (c)	Plant Cost (d)
1	Compressor Station at Burlington, Wa Placed in Service: Aug, 2001	1	1350 hp	$ 2,000,731
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
	Total			**$ 2,000,731**

Name of Respondent	This Report is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

COMPRESSOR STATIONS

Designate any station that was not operated during the past year. State in footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are comtemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year, and show in a footnote each unit's size and the date the unit was placed in operation.

3. For column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or power.

Line No.	Expenses (Except depreciation and taxes) Fuel (e)	Expenses (Except depreciation and taxes) Power (f)	Expenses (Except taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station in kWh (i)	Operational Data Total Compressor Hours of Operation During Year (j)	Operational Data Number of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1	$ 10,527	$ -	118,345			Not Available	1	Not Available
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
	$ 10,527	**$ -**	**$ 118,345**					

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2014**

GAS STORAGE PROJECTS

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (In Dth)			
1	Gas Delivered to Storage			
2	January			
3	February			
4	March			
5	April			
6	May			
7	June			
8	July			
9	August			
10	September			
11	October			
12	November			
13	December			
14	TOTAL (Total of lines 2 through 13)	None	None	None
15	Gas Withdrawn from Storage			
16	January			
17	February			
18	March			
19	April			
20	May			
21	June			
22	July			
23	August			
24	September			
25	October			
26	November			
27	December			
28	TOTAL (Total of lines 16 through 27)	None	None	None

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS STORAGE PROJECTS

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	
2	Cushion Gas (Including Native Gas)	
3	Total Gas in Reservoir (Total of Line 1 and 2)	
4	Certificated Storage Capacity	
5	Number of injection - Withdrawal Wells	
6	Number of Observation Wells	
7	Maximum Days' Withdrawal from Storage	
8	Date of Maximum Days' Withdrawal	
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	LNG Volume	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

TRANSMISSION MAINS

Kind of Material (a)	Diameter of Pipe (In Inches) (b)	Total Length In Use, Beg. of Year, Feet (c)	Laid During The Year, Feet (d)	Taken Up or Abandoned During Year (e)	Pipeline Footage Adjustments* (f)	Total Length In Use, End of Year, Feet (g)
Steel, Coated & Wrapped	2.00	-			255	255
Steel, Coated & Wrapped	4.00	1,340			1,966	3,306
Steel, Coated & Wrapped	6.00	-			37,523	37,523
Steel, Coated & Wrapped	8.00	200,896			311,778	512,674
Steel, Coated & Wrapped	10.00	39			-	39
Steel, Coated & Wrapped	12.00	9,665			20,862	30,527
Steel, Coated & Wrapped	16.00	252,447			2,597	255,044
Steel, Coated & Wrapped	20.00	45,774			-	45,774
Total Washington -		510,161	-	-	374,981	885,142
Steel, Coated & Wrapped	2.00	-			-	-
Steel, Coated & Wrapped	4.00	-			-	-
Steel, Coated & Wrapped	6.00	-			-	-
Steel, Coated & Wrapped	8.00	79,875			70	79,945
Steel, Coated & Wrapped	10.00	12			-	12
Steel, Coated & Wrapped	12.00	25,873			-	25,873
Steel, Coated & Wrapped	16.00	-			-	-
Steel, Coated & Wrapped	20.00	-			-	-
Total Oregon -		105,760	-	-	70	105,830
Steel, Coated & Wrapped	2.00	-	-	-	255	255
Steel, Coated & Wrapped	4.00	1,340	-	-	1,966	3,306
Steel, Coated & Wrapped	6.00	-	-	-	37,523	37,523
Steel, Coated & Wrapped	8.00	280,771	-	-	311,848	592,619
Steel, Coated & Wrapped	10.00	51	-	-	-	51
Steel, Coated & Wrapped	12.00	35,538	-	-	20,862	56,400
Steel, Coated & Wrapped	16.00	252,447	-	-	2,597	255,044
Steel, Coated & Wrapped	20.00	45,774	-	-	-	45,774
Total System -		615,921	-	-	375,051	990,972

***Column (f) adjustments due primarily to a reclassification of roughly 373,400' of 6", 8", 12", and 16" high pressure steel distribution main in Washington to transmission main. The remaining adjustments are due to ongoing corrections to our GIS data.**

BLANK PAGE

[Next page is 514-B]

DISTRIBUTION MAINS						
Kind of Material (a)	Diameter of Pipe (In Inches) (b)	Total Length In Use, Beg. of Year, Feet (c)	Laid During The Year, Feet (d)	Taken Up or Abandoned During Year (e)	Pipeline Footage Adjustments* (f)	Total Length In Use, End of Year, Feet (g)
Steel	0.00	70			(70)	-
Steel	0.625	88				88
Steel	0.75	14,141		(58)	997	15,080
Steel	1.00	19,515	11		(4,095)	15,431
Steel	1.25	4,777	10		89	4,876
Steel	1.50	-				-
Steel	2.00	9,772,708	13,906	(10,844)	(36,085)	9,739,685
Steel	2.50	42				42
Steel	3.00	239,029		(42)	(29)	238,959
Steel	4.00	2,502,501	1,847	(6,766)	(14,821)	2,482,761
Steel	5.00	-				-
Steel	6.00	1,163,237	359	(306)	(36,307)	1,126,983
Steel	7.00	1,276				1,276
Steel	8.00	893,479	220	(201)	(310,056)	583,441
Steel	10.00	34,425			4	34,429
Steel	12.00	255,786			(20,993)	234,793
Steel	16.00	11,941			(2,597)	9,345
Steel	20.00	-				-
Plastic	0.00	395			(395)	-
Plastic	0.50	1,476	389		(389)	1,476
Plastic	0.625	10,985			(35)	10,949
Plastic	0.75	49				49
Plastic	1.00	488,117	6,733		2,233	497,083
Plastic	1.25	334			42	376
Plastic	1.50	28				28
Plastic	2.00	7,064,906	71,844	(1,968)	(3,638)	7,131,143
Plastic	2.50	9				9
Plastic	4.00	1,569,708	9,662	(3,033)	20,636	1,596,974
Plastic	6.00	97,829	12,185		5,164	115,178
Plastic	8.00	307				307
Total Washington -		24,147,161	117,165	(23,218)	(400,345)	23,840,761
Steel	0.00	60				60
Steel	0.625	-				-
Steel	0.75	5,503			172	5,675
Steel	1.00	7,092		(4)	(1,189)	5,899
Steel	1.25	5,740			110	5,850
Steel	1.50	278				278
Steel	2.00	2,985,078	5,148	(8,035)	3,218	2,985,409
Steel	2.50	-				-
Steel	3.00	36,230			180	36,410
Steel	4.00	798,858	64	(2,499)	(4,345)	792,078
Steel	5.00	-				-
Steel	6.00	404,965			544	405,509
Steel	8.00	118,007				118,007
Steel	10.00	30,248				30,248
Steel	12.00	-				-
Steel	16.00	-				-
Plastic	0.00	-				-
Plastic	0.50	-	13		(13)	-
Plastic	0.625	810			(215)	595
Plastic	0.75	-				-
Plastic	1.00	444,862	8,673	(35)	612	454,112

DISTRIBUTION MAINS

Kind of Material (a)	Diameter of Pipe (In Inches) (b)	Total Length In Use, Beg. of Year, Feet (c)	Laid During The Year, Feet (d)	Taken Up or Abandoned During Year (e)	Pipeline Footage Adjustments* (f)	Total Length In Use, End of Year, Feet (g)
Plastic	1.25	55				55
Plastic	1.50	227				227
Plastic	2.00	2,857,410	21,025	(93)	(20,608)	2,857,734
Plastic	2.50	30				30
Plastic	4.00	513,482	7,141		117	520,740
Plastic	6.00	42,204	594		(626)	42,172
Total Oregon -		8,251,139	42,658	(10,666)	(22,043)	8,261,088
Steel	0.00	130	-	-	(70)	60
Steel	0.625	88	-	-	-	88
Steel	0.75	19,644	-	(58)	1,169	20,755
Steel	1.00	26,607	11	(4)	(5,284)	21,330
Steel	1.25	10,517	10	-	199	10,726
Steel	1.50	278	-	-	-	278
Steel	2.00	12,757,786	19,054	(18,879)	(32,867)	12,725,094
Steel	2.50	42	-	-	-	42
Steel	3.00	275,259	-	(42)	152	275,369
Steel	4.00	3,301,359	1,911	(9,264)	(19,167)	3,274,839
Steel	5.00	-	-	-	-	-
Steel	6.00	1,568,202	359	(306)	(35,763)	1,532,492
Steel	7.00	1,276	-	-	-	1,276
Steel	8.00	1,011,487	220	(201)	(310,058)	701,448
Steel	10.00	64,673	-	-	4	64,677
Steel	12.00	255,786	-	-	(20,993)	234,793
Steel	16.00	11,941	-	-	(2,597)	9,345
Steel	20	-				-
Plastic	0.00	395	-	-	(395)	-
Plastic	0.50	1,476	402	-	(402)	1,476
Plastic	0.625	11,795	-	-	(251)	11,544
Plastic	0.75	49	-	-	-	49
Plastic	1.00	932,979	15,406	(35)	2,845	951,195
Plastic	1.25	389	-	-	42	431
Plastic	1.50	256	-	-	(1)	255
Plastic	2.00	9,922,316	92,869	(2,061)	(24,247)	9,988,877
Plastic	2.50	39	-	-	-	39
Plastic	4.00	2,083,191	16,803	(3,033)	20,753	2,117,714
Plastic	6.00	140,033	12,779	-	4,538	157,350
Plastic	8.00	307	-	-	-	307
Total System -		32,398,300	159,824	(33,884)	(422,393)	32,101,849

***Column (f) adjustments due primarily to a reclassification of roughly 373,400' of 6", 8", 12", and 16" high pressure steel distribution main in Washington to transmission main. The remaining adjustments are due to ongoing corrections to our GIS data.**

SERVICE PIPES - GAS

Kind of Material (a)	Diameter of Pipe (In Inches) (b)	Number at Beginning of Year (c)	Number Added During The Year (d)	No. Removed or Abandoned During Year (e)	GIS Quantity Adjustments (f)*	Number at End of The Year (g)	Average Length In feet
Steel	various	110,677	74	(408)	710	111,053	
Plastic	various	96,672	1,653	(74)	(1,330)	96,921	
Total Washington -		207,349	1,727	(482)	(620)	207,974	71.66
Steel	various	30,098	21	(236)	125	30,008	
Plastic	various	36,850	916	(58)	(585)	37,123	
Total Oregon -		66,948	937	(294)	(460)	67,131	68.78
Steel	various	140,775	95	(644)	835	141,061	
Plastic	various	133,522	2,569	(132)	(1,915)	134,044	
Total System -		274,297	2,664	(776)	(1,080)	275,105	70.96

***Column (f) adjustments due to ongoing corrections to our GIS database**

CUSTOMER REGULATORS

Type	Allocation Rates	In Service Beginning Of Year	Added During The Year	Retired During The Year	Adjustments	In Service End Of Year
Washington						
Class I		150,050	1,101	(827)	0	150,324
Class II		6,564	221	(46)	0	6,739
Class III		2,939	54	(40)	0	2,954
Class IV		2,982	22	(22)	0	2,981
Total -	75.06%	162,534	1,398	(934)	0	162,996
Oregon						
Class I		41,181	366	(275)	0	41,272
Class II		1,831	73	(15)	0	1,889
Class III		837	18	(13)	0	841
Class IV		847	7	(7)	0	848
Total -	24.94%	44,697	464	(311)	0	44,852
Total System						
Class I		191,231	1,467	(1,102)	0	191,596
Class II		8,395	294	(61)	0	8,628
Class III		3,776	72	(53)	0	3,795
Class IV		3,829	29	(29)	0	3,829
Total -	100.00%	207,231	1,862	(1,245)	0	207,848

CUSTOMER METERS

Type	Allocation Rates	In Service Beginning Of Year	Added During The Year	Retired During The Year	Adjustments	In Service End Of Year
Washington						
Class I		198,877	6,295	-	-	205,172
Class II		11,163	335	-	-	11,498
Class III		3,579	218	-	-	3,797
Class IV & larger		1,742	175	-	-	1,917
Total -	75.06%	215,361	7,023	-	-	222,384
Oregon						
Class I		49,278	2,091	-	-	51,369
Class II		3,242	111	-	1	3,354
Class III		873	73	-	-	946
Class IV & larger		469	58	-	-	527
Total -	24.94%	53,862	2,333	-	1	56,196
Total System						
Class I		248,155	8,386	-	-	256,541
Class II		14,405	446	-	1	14,852
Class III		4,452	291	-	-	4,743
Class IV & larger		2,211	233	-	-	2,444
Total -	100.00%	269,223	9,356	-	1	278,580

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

TRANSMISSION SYSTEM PEAK DELIVERIES

1. Report below the total transmission system deliveries of gas (in Dth), excluding deliveries to storage, for the period of system peak deliveries indicated below, during the 12 months embracing the heating season overlapping the year's end for which this report is submitted. The season's peak normally will be reached before the due date of this report, April 30, which permits inclusion of the peak information required on this page. Add rows as necessary to report all data. Number additional rows 6.01, 6.02, etc.

Line No.	Description (a)	Dth of Gas Delivered to Interstate Pipelines (b)	Dth of Gas Delivered to Others (c)	Total (b) + (c) (d)
	SECTION A: SINGLE DAY PEAK DELIVERIES			
1				
2	Volumes of Gas Transported			
3	No-Notice Transportation			
4	Other Firm Transportation			
5	Interruptible Transportation			
5.01	Other (Describe)			
6				
7	TOTAL			
8	Volumes of gas withdrawn from storage under Storage Contracts			
9	No-Notice Transportation			
10	Other Firm Transportation			
11	Interruptible Transportation			
11.01	Other (Describe)			
12				
13	TOTAL			
14	Other Operational Activities			
15	Gas withdrawn from storage for system operations			
16	Reduction in Line Pack			
16.01	Other (Describe)			
17				
18	TOTAL			
19	**SECTION B: CONSECUTIVE THREE-DAY PEAK DELIVERIES**			
20				
21	Volumes of Gas Transported			
22	No-Notice Transportation			
23	Other Firm Transportation			
24	Interruptible Transportation			
24.01	Other (Describe)			
25				
26	TOTAL			
27	Volumes of gas withdrawn from storage under Storage Contracts			
28	No-Notice Transportation			
29	Other Firm Transportation			
30	Interruptible Transportation			
30.01	Other (Describe)			
31				
32	TOTAL			
33	Other Operational Activities			
34	Gas withdrawn from storage for system operations			
35	Reduction in Line Pack			
35.01	Other (Describe)			
36				
37	TOTAL			

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2014

AUXILIARY PEAKING FACILITIES

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery?
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Name of Respondent	This Report is:	Date of Report	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2014

GAS ACCOUNT - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. of FERC Form Nos. 2/2-A (b)	Total Amount of Dth Year to Date (c)	Current 3 months Ended Amount of Dth Quarterly Only (d)
01	Name of System:			
2	**GAS RECEIVED**			
3	Gas purchases (Accounts 800-805)		21,107,785	0
4	Gas of Others Received for Gathering (Account 489.1)	303	0	0
5	Gas of Others Received for Transmission (Account 489.2)	305	0	0
6	Gas of Others Received for Distribution (Account 489.3)	301	0	0
7	Gas of Others Received for Contract Storage (Account 489.4)	307	0	0
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)		0	0
9	Exchanged Gas Received from Others (Account 806)	328	0	0
10	Gas Received as Imbalances (Account 806)	328	0	0
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332	0	0
12	Other Gas Withdrawn from Storage (Explain)		1,148,604	0
13	Gas Received from Shippers as Compressor Station Fuel		0	0
14	Gas Received from Shippers as Lost and Unaccounted for		0	0
14.1	Other Receipts (specify) Customer-Owned Gas		73,308,516	0
15				
16	Total Receipts (Total of Lines 3 thru 14)		95,564,905	0
17	**GAS DELIVERED**			
18	Gas sales (Accounts 480-484)		21,600,234	0
19	Deliveries of gas gathered for others (Account 489.1)	303	0	0
20	Deliveries of gas transported for others (Account 489.2)	305	73,308,516	0
21	Deliveries of gas distributed for others (Account 489.3)	301	0	0
22	Deliveries of contract storage gas (Account 489.4)	307	0	0
23	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)		0	0
24	Exchange gas delivered to others (Account 806)	328	0	0
25	Gas delivered as imbalances (Account 806)	328	0	0
26	Deliveries of gas to others for transportation (Account 858)	332	0	0
27	Other gas delivered to storage (Explain)		375,349	0
28	Gas used for compressor station fuel	509	0	0
29	Other deliveries (Specify) Company used gas	331	10,462	0
30	Total Deliveries (Total Lines 17 thru 27) -		95,294,561	0
31	**GAS LOSSES AND GAS UNACCOUNTED FOR**			
32	Gas Losses and Unaccounted For		270,344	0
33	**TOTALS**			
34	Total Deliveries, Gas Losses & Unaccounted For		95,564,905	0

EXECUTIVE SALARY SUPPLEMENTAL DETAILS

1. Report below the name, title, and salary for each executive officer. An "executive officer" of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and the date the change in incumbency was made.

Line No.	Name of Officer (a)	Salary for Year (b)	Account Number (c)	Amount Assigned to WA (d)	Percent Increase Over Prior Year (e)	Reason for Increase (f)
1	K. Frank Morehouse, President and CEO of MDU Utility Group 1/	4/	9200	4/	4/	
2	David L. Goodin, Chairman of the Board 2/	4/	9200	4/	4/	
3	Mark A. Chiles, VP Controller, Asst. Treasure & Asst. Secretary 3/	4/	9200	4/	4/	
4	Eric P. Martuscelli, VP Operations	4/	9200	4/	4/	
5	Scott W. Madison, EVP & General Manager 3/	4/	9200	4/	4/	
6	Julie A. Krenz, Assistant Secretary 2/	4/	9200	4/	4/	
7	Paul K. Sandness, General Counsel and Secretary 2/	4/	9200	4/	4/	
8	Daniel S. Kuntz, Assistant Secretary 2/	4/	9200	4/	4/	
9	Michael J. Gardner, EVP-Utility Operations Support 1/	4/	9200	4/	4/	
10	Anne M. Jones, VP-HR, Customer Service, & Safety 1/	4/	9200	4/	4/	
11	Douglass A. Mahowald, Treasurer (Retired Nov 2014) 2/	4/	9200	4/	4/	
12	Jason A. Vollmer, Treasurer (Nov 2014) 2/					
13						
14	1/ Salary includes amount allocated to CNGC from MDU					
15	2/ Salary includes amount allocated to CNGC from MDUR					
16	3/ Salary includes amount allocated to CNGC from IGC					
17	4/ Confidential salary data available to WUTC upon request					
18						
19						
20						

EMPLOYEE COUNT BY CLASS AND TOTAL SALARIES BY CLASS

Pursuant to RCW 80.04.080, report below the number of employees by class (per company definition to be provided), and the total amount of salaries and wages paid each class.

Line No.	Employee Class (a)	Number of Employees (b)	Total Salaries & Wages Paid Each Class (c)
21			
22	Union	172	$ 11,183,502
23	Officers	11	$ 734,204 5/
24	Salary	137	$ 9,994,594
25			
26			
27	5/ - This is the amount of officer salary allocated to Cascade		
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			

Annual Report of Cascade Natural Gas Corporation

DATA REQUEST FOR STATISTICS REPORT

For the Year 2014

Line No.		Total Company Operations		Washington Operations	
		Current Year	Prior Year	Current Year	Prior Year
1	**Gas Service Revenues**				
2					
3	Residential Sales	$ 155,195,094	$ 144,083,109	$ 117,606,753	$ 108,259,750
4	Commercial Sales	$ 108,647,845	$ 94,855,621	$ 85,227,310	$ 72,848,971
5	Industrial Sales	$ 18,773,265	$ 15,360,627	$ 13,996,966	$ 11,413,364
6	Other Sales	$ -	$ -	$ -	$ -
7	Sales for Resale	$ -	$ -	$ -	$ -
8	Transportation of Gas of Others	$ 23,895,477	$ 23,444,372	$ 19,865,944	$ 19,477,932
9	Other Operating Revenues	$ 1,520,794	$ 1,571,220	$ 1,243,014	$ 1,341,392
10					
11	**Total Gas Service Revenues**	**$ 308,032,475**	**$ 279,314,948**	**$ 237,939,987**	**$ 213,341,409**
12					
13	**Therms of Gas Sold / Transported**				
14					
15	Residential Sales	149,116,396	160,256,646	111,069,761	118,686,353
16	Commercial Sales	115,367,791	118,174,473	87,543,210	88,029,725
17	Industrial Sales	24,032,255	23,470,466	17,389,369	17,283,142
18	Other Sales	-	-	-	-
19	Sales for Resale	-	-	-	-
20	Transportation of Gas of Others	971,223,295	1,014,219,859	733,085,157	754,823,799
21					
22	**Total Therms of Gas Sold & Transported**	**1,259,739,737**	**1,316,121,444**	**949,087,497**	**978,823,019**
23					
24	**Average Number of Gas Customers**				
25					
26	Residential	233,966	230,770	176,551	174,479
27	Commercial	34,634	34,406	25,022	24,893
28	Industrial	547	497	428	384
29	Other	-	-		-
30	Sales for Resale	-	-	-	-
31	Transportation of Gas of Others	230	227	195	192
32					
33	**Average Number of Customers**	**269,377**	**265,900**	**202,196**	**199,948**
34					
35	Trans. & Distrn. Mains - Feet (End of Year)	33,092,821	33,014,222	24,725,903	24,657,322
36	No. of Meters in Serv. & Held in Reserve (Ave.)	278,580	269,224	222,384	215,362
37	Average B.T.U. Content Per Cu. Ft.	-	-	-	-

Depreciation, Depletion, and Amortization of Gas Plant

Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (b)	Estimated Average Service Life (c)	Net Salvage (percent) (d)	Applied Depreciation Rate(s) (percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
1							
2	**Intangible Plant**						
3	303	20,927,191	15	0%	0.00%		12.00
4							
5	**Transmission Plant**						
6	3652	1,018,397	70	0%	0.00%	S6	19.76
7	3670	9,985,353	60	0%	0.00%	R2	16.53
8	3690	156,139	40	0%	0.00%	R2.5	-1.07
9							
10	**Distribution Plant**						
11	3742	1,922,323	60	0%	0.00%	R2	42.15
12	3751	996,782	40	0%	0.00%	R3	1.81
13	3761	101,271,148	60	0%	0.00%	R2	15.22
14	3762	113,912,142	60	0%	0.00%	R3	41.98
15	3763	83,404,885	60	0%	0.00%	R2	44.57
16	3770	2,000,731	20	0%	0.00%		7.53
17	3780	15,860,369	40	0%	0.00%	R2.5	27.14
18	3801	62,815,875	45	0%	0.00%	R5	-17.89
19	3803	88,476,909	45	0%	0.00%	R5	29.78
20	3810	37,668,866	33	0%	0.00%	R5	21.89
21	3820	22,112,269	40	0%	0.00%	R1.5	22.79
22	3830	7,648,096	45	0%	0.00%	R5	28.83
23	3850	7,583,274	28	0%	0.00%	R1.5	16.17
24							
25	**General Plant**						
26	3901	13,119,400	45	0%	0.00%	R3	15.69
27	3911	0	7	0%	0.00%	S0	0.00
28	3912	2,266,768	6	0%	0.00%	S-.5	0.00
29	3913	1,427,304	7	0%	0.00%	S0	7.31
30	3914	282,844	20	0%	0.00%	L2	31.37
31	3915	1,316,903	30	0%	0.00%	R4	30.95
32	3921	286,722	9	0%	0.00%	L2	5.13
33	3922	9,006,752	9	0%	0.00%	L2	5.89
34	3930	56,455	30	0%	0.00%	R2	22.10
35	3941	4,883,609	30	0%	0.00%	R2	20.95
36	3950	102,616	25	0%	0.00%	R2	14.73
37	3961	489,031	16	0%	0.00%	L3	11.63
38	3962	2,267,263	16	0%	0.00%	L3	13.45
39	3971	147,970	25	0%	0.00%	R1.5	8.79
40	3972	2,896,131	10	0%	0.00%	R3	0.30
41	3973	651,876	10	0%	0.00%	R4	6.53
42	3974	385,140	25	0%	0.00%	R2.5	23.49
43	3980	55,918	20	0%	0.00%	S1	22.39
44							
45							
46							
47							
48							
49							
50							

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 09/30/2017)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Cascade Natural Gas Corporation	**End of** 2014/Q4

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information form natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

(a) Submit Forms 2, 2-A and 3-Q electronically through the submission software at http://www.ferc.gov/docs-filing/eforms/form-2/elec-subm-soft.asp .

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

Secretary of the Commission
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

(i) Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 158.10-158.12 for specific qualifications.)

Reference	Reference Schedules Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

Filers should state in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist

.

(e) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders" and "CPA Certification Statement," have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission website at http://www.ferc.gov/help/how-to.asp

(f) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: http://www.ferc.gov/docs-filing/eforms/form-2/form-2.pdf and http://www.ferc.gov/docs-filing/eforms/form-2a/form-2a.pdf, respectively. Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

(a) FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)

(b) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and

(c) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,623 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 250 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 165 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or Dth) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions**.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Footnote and further explain accounts or pages as necessary.

IX. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

X. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

DEFINITIONS	
I.	Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).
II.	Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
III.	Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.
IV	Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW
(Natural Gas Act, 15 U.S.C. 717-717w)

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this act; and may prescribe the form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. § 717t-1(a).

BLANK PAGE

QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Cascade Natural Gas Corporation	Year/Period of Report End of 2014/Q4
03 Previous Name and Date of Change (If name changed during year)	
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 8113 West Grandridge Boulevard, Kennewick, WA 99336-7166	
05 Name of Contact Person Tammy Nygard	06 Title of Contact Person Director, Accounting & Finance
07 Address of Contact Person (Street, City, State, Zip Code) 8113 West Grandridge Boulevard, Kennewick, WA 99336-7166	

08 Telephone of Contact Person, Including Area Code	This Report Is:	10 Date of Report (Mo, Da, Yr)
509-734-4516	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

11 Name	12 Title
Tammy Nygard	Director, Accounting & Finance
13 Signature Tammy Nygard	14 Date Signed 03/20/2015

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

List of Schedules (Natural Gas Company)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

List of Schedules (Natural Gas Company) (continued)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

General Information

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Tammy Nygard
Director, Accounting & Finance
8113 West Grandridge Boulevard
Kennewick, Washington 99336-7166

2. Provide the name of the State under the laws of which respondent is incorporated and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated in the State of Washington - January 2, 1953

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Natural gas distribution in the states of Washington and Oregon

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes... Enter the date when such independent accountant was initially engaged:
(2) [X] No

Control Over Respondent

1. Report in column (a) the names of all corporations, partnerships, business trusts, and similar organizations that directly, indirectly, or jointly held control (see page 103 for definition of control) over the respondent at the end of the year. If control is in a holding company organization, report in a footnote the chain of organization.
2. If control is held by trustees, state in a footnote the names of trustees, the names of beneficiaries for whom the trust is maintained, and the purpose of the trust.
3. In column (b) designate type of control over the respondent. Report an "M" if the company is the main parent or controlling company having ultimate control over the respondent. Otherwise, report a "D" for direct, an "I" for indirect, or a "J" for joint control.

Line No.	Company Name (a)	Type of Control (b)	State of Incorporation (c)	Percent Voting Stock Owned (d)
1	MDU Resources Group, Inc. (MDUR)	M	DE	100.00
2	MDU Energy Capital, LLC	I	DE	100.00
3	Praire Cascade Energy Holdings, LLC (PCEH)	D	DE	100.00
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Corporations Controlled by Respondent

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.
4. In column (b) designate type of control of the respondent as "D" for direct, an "I" for indirect, or a "J" for joint control.

DEFINITIONS

----

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary that exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned (d)	Footnote Reference (e)
1	CGC Resources, Inc.	D	Pipeline Capacity Management	100	Not used
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Security Holders and Voting Powers

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes that each could cast on that date if a meeting were held. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the company did not close the stock book or did not compile a list of stockholders within one year prior to the end of the year, or if since it compiled the previous list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement how such security became vested with voting rights and give other important details concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish details concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets any officer, director, associated company, or any of the 10 largest security holders is entitled to purchase. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy.	3. Give the date and place of such meeting:
	Total: By Proxy:	

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	1,000	1,000		
6	TOTAL number of security holders	1	1		
7	TOTAL votes of security holders listed below	1,000	1,000		
8					
9					
10					
11	Cascade is a wholly-owned subsidiary of MDU Resources Group, Inc.				
12	MDU Resources Group, Inc.				
13	PO Box 5650				
14	Bismarck, ND 58506-5650				
15					
16					
17					
18					
19					
20					

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) __ A Resubmission	12/31/2014	2014/Q4

Important Changes During the Quarter/Year

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service.

Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.

6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None
2. None
3. None
4. None
5. None
6. None
7. None
8. Wages for hourly employees increased by 3.25% in April 2014.
9. None
10. None
11. None
12. None
13. None

BLANK PAGE

[Next page is 110]

Comparative Balance Sheet (Assets and Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	801,092,163	767,957,540
3	Construction Work in Progress (107)	200-201	17,169,118	12,554,927
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	818,261,281	780,512,467
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		405,497,367	385,942,905
6	Net Utility Plant (Total of line 4 less 5)		412,763,914	394,569,562
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	0
9	Nuclear Fuel (Total of line 7 less 8)		0	0
10	Net Utility Plant (Total of lines 6 and 9)		412,763,914	394,569,562
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	0	0
13	System Balancing Gas (117.2)	220	0	0
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	0	0
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		202,030	202,030
18	(Less) Accum. Provision for Depreciation and Amortization (122)		0	0
19	Investments in Associated Companies (123)	222-223	0	0
20	Investments in Subsidiary Companies (123.1)	224-225	0	0
21	(For Cost of Account 123.1 See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	10,051,743	10,095,569
24	Sinking Funds (125)		0	0
25	Depreciation Fund (126)		0	0
26	Amortization Fund - Federal (127)		0	0
27	Other Special Funds (128)		0	0
28	Long-Term Portion of Derivative Assets (175)		0	0
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		10,253,773	10,297,599
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		25,580,052	2,022,453
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		2,700	2,900
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		0	51,812
37	Customer Accounts Receivable (142)		14,617,476	16,894,569
38	Other Accounts Receivable (143)		643,801	402,611
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		518,925	527,021
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		5,348,433	123,269
42	Fuel Stock (151)		0	0
43	Fuel Stock Expenses Undistributed (152)		0	0

Comparative Balance Sheet (Assets and Other Debits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		6,294,298	6,093,326
46	Merchandise (155)		0	0
47	Other Materials and Supplies (156)		0	0
48	Nuclear Materials Held for Sale (157)		0	0
49	Allowances (158.1 and 158.2)		0	0
50	(Less) Noncurrent Portion of Allowances		0	0
51	Stores Expense Undistributed (163)		0	0
52	Gas Stored Underground-Current (164.1)	220	133,289	960,973
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	883,970	2,893,474
54	Prepayments (165)	230	5,615,309	4,750,729
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		0	0
57	Rents Receivable (172)		0	0
58	Accrued Utility Revenues (173)		32,260,648	32,266,682
59	Miscellaneous Current and Accrued Assets (174)		0	0
60	Derivative Instrument Assets (175)		0	0
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
62	Derivative Instrument Assets - Hedges (176)		0	0
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		90,861,051	65,935,777
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		2,302,962	2,303,125
67	Extraordinary Property Losses (182.1)	230	0	0
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
69	Other Regulatory Assets (182.3)	232	52,727,311	36,052,147
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		(78,383)	(100,767)
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	21,961,707	19,813,630
75	Deferred Losses from Disposition of Utility Plant (187)		0	0
76	Research, Development, and Demonstration Expend. (188)		0	0
77	Unamortized Loss on Reacquired Debt (189)		908,183	949,154
78	Accumulated Deferred Income Taxes (190)	234-235	22,703,374	20,926,644
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		100,525,154	79,943,933
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		614,403,892	550,746,871

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	1,000	1,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	152,703,952	117,703,952
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	42,672,119	47,283,729
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	0	0
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		195,377,071	164,988,681
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257	0	0
18	(Less) Reacquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	189,662,000	164,863,000
21	Unamortized Premium on Long-Term Debt (225)	258-259	0	0
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	0	0
23	(Less) Current Portion of Long-Term Debt		0	0
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		189,662,000	164,863,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases-Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		14,270,253	13,346,221
29	Accumulated Provision for Pensions and Benefits (228.3)		8,069,959	6,562,655
30	Accumulated Miscellaneous Operating Provisions (228.4)		24,135	24,135
31	Accumulated Provision for Rate Refunds (229)		0	0

Comparative Balance Sheet (Liabilities and Other Credits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		606,421	569,829
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		22,970,768	20,502,840
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		0	11,500,000
39	Accounts Payable (232)		25,808,922	29,068,725
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		1,450,342	1,500,660
42	Customer Deposits (235)		1,773,982	1,749,584
43	Taxes Accrued (236)	262-263	8,304,409	9,299,598
44	Interest Accrued (237)		2,698,426	2,260,220
45	Dividends Declared (238)		4,160,000	4,160,000
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		6,482	3,002
49	Miscellaneous Current and Accrued Liabilities (242)	268	8,172,382	7,601,991
50	Obligations Under Capital Leases-Current (243)		0	0
51	Derivative Instrument Liabilities (244)		0	0
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
53	Derivative Instrument Liabilities - Hedges (245)		0	0
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		52,374,945	67,143,780
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		2,901,261	4,296,051
58	Accumulated Deferred Investment Tax Credits (255)		425,699	483,242
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	17,328,327	11,513,466
61	Other Regulatory Liabilities (254)	278	4,133,312	4,652,943
62	Unamortized Gain on Reacquired Debt (257)	260	0	0
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	0
64	Accumulated Deferred Income Taxes - Other Property (282)		96,138,132	84,106,817
65	Accumulated Deferred Income Taxes - Other (283)		33,092,377	28,196,051
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		154,019,108	133,248,570
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		614,403,892	550,746,871

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Statement of Income

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting mehods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	UTILITY OPERATING INCOME					
2	Gas Operating Revenues (400)	300-301	308,032,475	279,314,948	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	223,018,531	193,471,588	0	0
5	Maintenance Expenses (402)	317-325	5,931,468	5,588,163	0	0
6	Depreciation Expense (403)	336-338	19,613,636	19,158,714	0	0
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0	0	0	0
8	Amortization and Depletion of Utility Plant (404-405)	336-338	2,172,996	1,523,238	0	0
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	0	0	0	0
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0	0	0
11	Amortization of Conversion Expenses (407.2)		0	0	0	0
12	Regulatory Debits (407.3)		0	0	0	0
13	(Less) Regulatory Credits (407.4)		0	0	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	29,146,595	26,541,850	0	0
15	Income Taxes-Federal (409.1)	262-263	(7,266,100)	(481,297)	0	0
16	Income Taxes-Other (409.1)	262-263	(406,771)	(41,718)	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	14,782,814	9,098,512	0	0
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	0	0	0	0
19	Investment Tax Credit Adjustment-Net (411.4)		(57,543)	(63,288)	0	0
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0	0	0
21	Losses from Disposition of Utility Plant (411.7)		0	0	0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0	0	0
23	Losses from Disposition of Allowances (411.9)		0	0	0	0
24	Accretion Expense (411.10)		0	0	0	0
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		286,935,626	254,795,762	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		21,096,849	24,519,186	0	0

Statement of Income

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	0	0	308,032,475	279,314,948	0	0
3						
4	0	0	223,018,531	193,471,588	0	0
5	0	0	5,931,468	5,588,163	0	0
6	0	0	19,613,636	19,158,714	0	0
7	0	0	0	0	0	0
8	0	0	2,172,996	1,523,238	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	0	0	0	0
13	0	0	0	0	0	0
14	0	0	29,146,595	26,541,850	0	0
15	0	0	(7,266,100)	(481,297)	0	0
16	0	0	(406,771)	(41,718)	0	0
17	0	0	14,782,814	9,098,512	0	0
18	0	0	0	0	0	0
19	0	0	(57,543)	(63,288)	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	0	0	0
25	0	0	286,935,626	254,795,762	0	0
26	0	0	21,096,849	24,519,186	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Statement of Income(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		21,096,849	24,519,186	0	0
28	OTHER INCOME AND DEDUCTIONS					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues form Merchandising, Jobbing and Contract Work (415)		0	0	0	0
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0	0	0	0
33	Revenues from Nonutility Operations (417)		22,155	22,912	0	0
34	(Less) Expenses of Nonutility Operations (417.1)		0	0	0	0
35	Nonoperating Rental Income (418)		0	0	0	0
36	Equity in Earnings of Subsidiary Companies (418.1)	119	0	0	0	0
37	Interest and Dividend Income (419)		378,962	201,519	0	0
38	Allowance for Other Funds Used During Construction (419.1)		320,960	(563)	0	0
39	Miscellaneous Nonoperating Income (421)		40,686	23,112	0	0
40	Gain on Disposition of Property (421.1)		0	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		762,763	246,980	0	0
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		0	0	0	0
44	Miscellaneous Amortization (425)		0	0	0	0
45	Donations (426.1)	340	237,332	210,111	0	0
46	Life Insurance (426.2)		0	0	0	0
47	Penalties (426.3)		5,016	679	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		117,835	113,169	0	0
49	Other Deductions (426.5)		350	40	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	360,533	323,999	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	2,962	2,604	0	0
53	Income Taxes-Federal (409.2)	262-263	(501)	1,503	0	0
54	Income Taxes-Other (409.2)	262-263	(1,716)	137	0	0
55	Provision for Deferred Income Taxes (410.2)	234-235	0	0	0	0
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	0	0	0	0
57	Investment Tax Credit Adjustments-Net (411.5)		0	0	0	0
58	(Less) Investment Tax Credits (420)		0	0	0	0
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		745	4,244	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		401,485	(81,263)	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		9,119,099	7,578,332	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	165,491	128,814	0	0
64	Amortization of Loss on Reacquired Debt (428.1)		40,971	67,790	0	0
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	0	0	0	0
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		0	0	0	0
67	Interest on Debt to Associated Companies (430)	340	0	0	0	0
68	Other Interest Expense (431)	340	426,797	1,258,825	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		289,081	263,260	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		9,463,277	8,770,501	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		12,035,057	15,667,422	0	0
72	EXTRAORDINARY ITEMS					
73	Extraordinary Income (434)		0	0	0	0
74	(Less) Extraordinary Deductions (435)		0	0	0	0
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0	0	0
76	Income Taxes-Federal and Other (409.3)	262-263	0	0	0	0
77	Extraordinary Items after Taxes (Total of line 75 less line 76)		0	0	0	0
78	Net Income (Total of lines 71 and 77)		12,035,057	15,667,422	0	0

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 12/31/2014	End of 2014/Q4

STATEMENT OF INCOME (continued)

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
27	-	-	21,096,849	24,519,186	-	-
28	[redacted]					
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	22,155	22,912	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	378,962	201,519	-	-
38	-	-	320,960	(563)	-	-
39	-	-	40,686	23,112	-	-
40	-	-	-	-	-	-
41	-	-	762,763	246,980	-	-
42	[redacted]					
43			-	-		
44			-	-		
45			237,332	210,111		
46			-	-		
47			5,016	679		
48			117,835	113,169		
49	-	-	350	40	-	-
50	-	-	360,533	323,999	-	-
51	[redacted]					
52			2,962	2,604		
53	-	-	(501)	1,503	-	-
54	-	-	(1,716)	137	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-			-	-
59	-	-	745	4,244	-	-
60	-	-	401,485	(81,263)	-	-
61	[redacted]					
62	-	-	9,119,099	7,578,332	-	-
63	-	-	165,491	128,814	-	-
64	-	-	40,971	67,790	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	426,797	1,258,825	-	-
69	-	-	(289,081)	(263,260)	-	-
70	-	-	9,463,277	8,770,501	-	-
71	-	-	12,035,057	15,667,422	-	-
72	[redacted]					
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	12,035,057	15,667,422	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liabililty Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges (Insert Category) (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4				15,667,422	15,667,422
5					
6					
7					
8					
9				12,035,057	12,035,057
10					

Statement of Retained Earnings

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		47,283,729	48,284,212
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		12,035,057	15,667,422
7	Appropriations of Retained Earnings (Account 436)			
8	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
9	Dividends Declared-Preferred Stock (Account 437)			
10	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
11	Dividends Declared-Common Stock (Account 438)			
12	TOTAL Dividends Declared-Common Stock (Account 438) (footnote details)		16,646,667	16,667,905
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings			
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		42,672,119	47,283,729
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)			
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines			
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 1		42,672,119	47,283,729
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
26	Balance-End of Year			

BLANK PAGE

[Next page is 120]

Statement of Cash Flows

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 116)	12,035,057	16,508,977
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	21,786,632	20,681,952
5	Amortization of (Specify) (footnote details): Gas cost changes	(6,584,905)	(22,163,001)
6	Deferred Income Taxes (Net)	14,667,728	8,301,947
7	Investment Tax Credit Adjustments (Net)	57,543	63,288
8	Net (Increase) Decrease in Receivables	(4,943,569)	(14,194,780)
9	Net (Increase) Decrease in Inventory	2,636,216	(837,523)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	(2,234,463)	5,795,910
12	Net (Increase) Decrease in Other Regulatory Assets		
13	Net Increase (Decrease) in Other Regulatory Liabilities		
14	(Less) Allowance for Other Funds Used During Construction		
15	(Less) Undistributed Earnings from Subsidiary Companies		
16	Other (footnote details): Net change in other deferred balances	(3,261,512)	(1,510,601)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	34,158,727	12,646,169
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(40,984,880)	(33,608,449)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction	320,960	(563)
27	Other (footnote details): Net increase in customer advances for construction	(1,394,790)	(324,104)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(42,700,630)	(33,931,990)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	114,642	(455,629)
32			
33	Investments in and Advances to Assoc. and Subsidiary Companies		
34	Contributions and Advances from Assoc. and Subsidiary Companies		
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies		
37			
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		

Statement of Cash Flows (continued)

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
40	Loans Made or Purchased		
41	Collections on Loans		
42			
43	Net (Increase) Decrease in Receivables		
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other (footnote details): SERP Assets	490,988	552,169
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(42,095,000)	(33,835,450)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	24,834,672	50,000,000
54	Preferred Stock		
55	Common Stock	35,000,000	
56	Other (footnote details):		
57	Net Increase in Short-term Debt (c)	(11,500,000)	9,500,000
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	48,334,672	59,500,000
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(201,000)	(24,227,000)
63	Preferred Stock		
64	Common Stock		
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(16,640,000)	(12,480,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	31,493,672	22,793,000
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	23,557,399	1,603,719
75			
76	Cash and Cash Equivalents at Beginning of Period	2,025,353	421,634
77			
78	Cash and Cash Equivalents at End of Period	25,582,752	2,025,353

Notes to Financial Statements

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
13. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

The accompanying notes relate to MDU Energy Capital, LLC and its subsidiary companies, while the financial statements in this FORM 2 Report reflect only the unconsolidated statements of Cascade Natural Gas Corporation. Cascade's subsidiary companies were dissolved as of 12/31/08 and do not have a material effect on the Notes to the Financial Statements.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2014 and 2013

Definitions

The following abbreviations and acronyms used in these Financial Statements and Notes defined below:

Abbreviation or Acronym

AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
Cascade	Cascade Natural Gas Corporation, a direct wholly owned subsidiary of PCEH
Company	MDU Energy Capital, LLC, a direct wholly owned subsidiary of MDU
EBITDA	Earnings before interest, taxes, depreciation and amortization
EIN	Employer Identification Number
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Intermountain	Intermountain Gas Company, a direct wholly owned subsidiary of PIEH
IPUC	Idaho Public Utilities Commission
MDU	MDU Resources Group, Inc.
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of MDU
PCEH	Prairie Cascade Energy Holdings, LLC, a direct wholly owned subsidiary of the Company
PIEH	Prairie Intermountain Energy Holdings, LLC, a direct wholly owned subsidiary of the Company
OPUC	Oregon Public Utility Commission
PRP	Potentially Responsible Party
RP	Rehabilitation plan
WUTC	Washington Utilities and Transportation Commission

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2014 and 2013

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The Company is incorporated under the laws of the state of Delaware and is a direct wholly owned subsidiary of MDU. The Company is parent to PCEH, and its wholly owned subsidiary Cascade, and PIEH, and its wholly owned subsidiary Intermountain.

Cascade and Intermountain's natural gas distribution operations sell natural gas at retail and provide natural gas transportation services to over 606,000 residential, commercial and industrial customers in 170 communities. The Cascade service territory consists of towns in western, southeastern and south-central Washington and central and eastern Oregon. The Intermountain service territory is located solely in southern Idaho, encompassing communities located across the Snake River Plain. Cascade is subject to regulation by the WUTC and the OPUC. Intermountain is subject to regulation by the IPUC. These markets tend to be seasonal and sales to residential and commercial customers are influenced by fluctuations in temperature, particularly during the winter season. Consumption is also influenced by the energy efficiency of customers' appliances, as well as consumer decisions to reduce natural gas usage in response to higher prices.

The consolidated financial statements and disclosures of the Company are presented in accordance with GAAP. The accounting policies followed by Cascade and Intermountain are generally subject to the FERC.

Cascade and Intermountain account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the applicable state public utility commissions. See Note 3 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2014, up to the date of the issuance of these consolidated financial statements on April 3, 2015, that would require recognition or disclosure in the financial statements.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts. The total balance of receivables past due 90 days or more was $1.0 million and $803,000 as of December 31, 2014 and 2013, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible.

The Company's allowance for doubtful accounts at December 31, 2014 and 2013 was $847,000 and $971,000, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage, consisted of materials and supplies of $9.0 million and $8.6 million as of December 31, 2014 and 2013, respectively. These inventories were stated at the lower of average cost or market value. Natural gas in storage is carried at cost using the first-in, first-out method at Cascade and using the average-cost method at Intermountain. Natural gas in storage is expected to be used within one year and the value included in inventories was $6.1 million and $8.9 million at December 31, 2014 and 2013, respectively.

Investments
The Company's investments include the cash surrender value of life insurance policies and an insurance contract. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. For more information, see Notes 4 and 8.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. The amount of AFUDC and interest capitalized for the years ended December 31 was as follows:

	2014	2013
	(In thousands)	
AFUDC - borrowed	**$ 930**	$ 751
AFUDC - equity	**$ 1,816**	$ (1)

Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets. The Company collects removal costs for plant assets in regulated utility rates and records them as a regulatory liability, which is included in other regulatory liabilities-noncurrent.

Property, plant and equipment at December 31 was as follows:

	2014	2013	Weighted Average Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Distribution plant	**$ 1,076,531**	$ 1,036,420	39
Transmission plant	**89,933**	89,239	51
Storage plant	**20,161**	17,022	40
General plant	**97,475**	93,576	21
Other plant	**34,187**	27,775	14
Non-depreciable plant	**6,370**	6,286	-
Construction in progress	**47,611**	36,544	-
Less: Accumulated depreciation and amortization	**501,499**	484,657	
Net property, plant and equipment	**$ 870,769**	$ 822,205	

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No impairment losses were recorded in 2014 and 2013. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. MDU and the Company perform the annual review for goodwill impairment at the reporting unit level, which MDU has determined to be the operating segment. This review is also performed at the Company level as separate financial statements are prepared.

The goodwill impairment test is a two-step process. The first step of the impairment test involves comparing the fair value of the reporting unit to its carrying value. If the fair value of the reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of the reporting unit is less than its carrying value, step two of the test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2014 and 2013, there were no impairment losses recorded. At December 31, 2014, the fair value substantially exceeded the carrying value for the Company level on a separate basis. For more information on goodwill, see Note 2.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital. The weighted average cost of capital of 5.0 percent, and a long-term growth rate projection of 3.1 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2014. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies. These multiples are applied to operating data to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Cascade and Intermountain was $52.3 million and $57.7 million at December 31, 2014 and 2013, respectively. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenue net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Asset retirement obligations

The Company performed detailed assessments of ARO’s for the removal of natural gas transmission, distribution, and storage facilities. The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a regulatory asset or liability. Certain ARO’s have been identified, however, based on the indeterminate life of those assets, an ARO calculation cannot be made, and accordingly, an ARO has not been recorded for those items. For more information on asset retirement obligations, see Note 6.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public utility commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments over a 12 month period. Natural gas costs recoverable through rate adjustments were $8.9 million and $4.0 million at December 31, 2014 and 2013, respectively. Natural gas costs refundable through rate adjustments were $13.2 million and $16.9 million at December 31, 2014 and 2013, respectively.

Income taxes
MDU and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by MDU, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. MDU makes a similar allocation for state income taxes paid in connection with combined state filings. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Regulated entities are required to recognize such adjustment to deferred income taxes as regulatory assets or liabilities if it is probable that such amounts will be recovered from or refunded to customers in future rates. Taxes recoverable from customers have been recorded as a regulatory asset and are included in deferred charges and other assets. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other regulatory liabilities-noncurrent. These regulatory assets and liabilities are expected to be recovered from or refunded to customers in future rates in accordance with applicable regulatory procedures.

Consistent with orders and directives of the IPUC, Intermountain does not provide state deferred income tax expense for certain income tax temporary differences and instead recognized the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, the Company’s effective income tax rate is impacted as these differences arise and reverse.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public utility commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Use of estimates
The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; unbilled revenues; actuarially determined benefit costs; and asset retirement obligations. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information
Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

	2014	2013
	(In thousands)	
Interest, net of amount capitalized	**$ 20,211**	$ 19,845
Income taxes refunded, net	**$ (4,758)**	$ (5,657)

Noncash investing transactions at December 31 were as follows:

	2014	2013
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 1,536**	$ 1,838

New accounting standards
Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. This guidance will be effective for the Company on January 1, 2017. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is evaluating the effects the adoption of the new revenue guidance will have on its results of operations, financial position, cash flows and disclosures, as well as its method of adoption.

NOTE 2 – GOODWILL
The carrying amount of goodwill for the years ended December 31, 2014 and 2013 remained unchanged at $340,924. No impairments of goodwill have been recorded.

NOTE 3 – REGULATORY ASSETS AND LIABILITIES

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period *	**2014**	2013
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(c)	**$ 58,488**	$ 37,993
Manufactured gas plant remediation (a)	Determined upon filing	**17,276**	15,434
Taxes recoverable from customers (a)	Over plant lives	**9,199**	6,593
Natural gas costs recoverable through rate adjustments	Up to 12 months	**8,923**	3,983
Conservation activities (a)	Up to 28 months	**2,945**	3,589
Long-term debt refinancing costs (a)	Up to 23 years	**1,176**	1,290
Other (a)	Largely not in recovery	**500**	457
Total regulatory assets		**98,507**	69,339
Regulatory liabilities:			
Plant removal costs (b)		**195,708**	185,793
Natural gas costs refundable through rate adjustments		**13,238**	16,874
Taxes refundable to customers (b)		**9,586**	9,109
Other (b)		**6,871**	8,460
Total regulatory liabilities		**225,403**	220,236
Net regulatory position		**$(126,896)**	$(150,897)

* *Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.*
(a) Included in other regulatory assets - noncurrent on the Consolidated Balance Sheets.
(b) Included in other regulatory liabilities - noncurrent on the Consolidated Balance Sheets.
(c) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2014 and 2013, approximately $89.3 million and $68.8 million, respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

NOTE 4 – FAIR VALUE MEASUREMENTS

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $3.0 million and $2.9 million as of December 31, 2014 and 2013, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2014 and 2013 were $160,000 and $624,000, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The fair value of the Company's money market funds approximates cost.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company’s Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer.

The estimated fair value of the Company’s Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2014 and 2013, there were no transfers between Levels 1 and 2.

The Company’s assets and liabilities measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 55	$ ---	$ 55
Insurance contract*	---	3,048	---	3,048
Total assets measured at fair value	$ ---	$ 3,103	$ ---	$ 3,103

** The insurance contract invests approximately 20 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies, 32 percent in fixed-income investments and 1 percent in cash equivalents.*

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Money market funds	$ ---	$ 565	$ ---	$ 565
Insurance contract*	---	2,888	---	2,888
Total assets measured at fair value	$ ---	$ 3,453	$ ---	$ 3,453

** The insurance contract invests approximately 29 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies and 15 percent in fixed-income investments.*

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2014		2013	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 446,753**	**$ 497,661**	$ 409,227	$ 419,506

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

NOTE 5 – DEBT

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2014	Amount Outstanding at December 31, 2013	Letters of Credit at December 31, 2014	Expiration Date
			(Dollars in millions)			
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (a)	$ ---	$ 11.5	$ 2.2 (b)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (c)	$ 21.0	$ 3.0	$ ----	7/13/18

(a) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million.
(b) An outstanding letter of credit reduces the amount available under the credit agreement.
(c) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million.

The following includes information related to the preceding table.

Long-term debt
MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired; however, there is debt outstanding that is reflected in the following table of long-term debt outstanding. The master shelf agreement contains customary covenants and provisions, including covenants of the Company not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of the Company's earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Cascade Natural Gas Corporation Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the revolving credit agreement.

On January 15, 2015, Cascade issued $25.0 million of Senior Notes with due dates ranging from January 15, 2045 to January 15, 2055 at a weighted average interest rate of 4.2 percent.

Intermountain Gas Company Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

	2014	2013
	(In thousands)	
Senior Notes at a weighted average rate of 5.10%, due on dates ranging from October 1, 2015 to November 24, 2055	**$ 351,091**	$ 331,364
Medium-Term Notes, at a weighted average rate of 7.32% due on dates ranging from September 15, 2027 to March 16, 2029	**35,000**	35,000
Credit agreement at a rate of 3.33% due July 13, 2018	**21,000**	3,000
Other notes, at a weighted average rate of 5.23% due on dates ranging from September 1, 2020 to February 1, 2035	**39,662**	39,863
Total long-term debt	**446,753**	409,227
Less current maturities	**55,273**	5,273
Net long-term debt	**$ 391,480**	$ 403,954

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2014, aggregate $55.3 million in 2015; $5.3 million in 2016; $40.3 million in 2017; $26.3 million in 2018; none in 2019 and $319.6 million thereafter.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The Company records asset retirement obligations related to certain natural gas distribution system assets as asset retirement obligations.

A reconciliation of the Company's liability, which is included in other regulatory liabilities-noncurrent, for the years ended December 31 was as follows:

	2014	2013
	(In thousands)	
Balance at beginning of year	**$570**	$547
Accretion expense	**36**	23
Balance at end of year	**$606**	$570

The Company believes that largely all expenses related to asset retirement obligations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

NOTE 7 – INCOME TAXES

Income before income taxes for the years ended December 31, 2014 and 2013 was $26,717 and $37,849, respectively.

Income tax expense for the years ended December 31 was as follows:

	2014	2013
	(In thousands)	
Current:		
Federal	**$ (14,259)**	$ 1,420
State	**(992)**	(918)
	(15,251)	502
Deferred:		
Income taxes –		
Federal	**23,357**	12,096
State	**945**	318
Investment tax credit	**(635)**	(159)
	23,667	12,255
Change in uncertain tax positions	**(1,429)**	---
Change in accrued interest (income)	**(15)**	39
Total income tax expense	**$ 6,972**	$ 12,796

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2014	2013
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 77,144**	$ 75,476
Contingency reserve	**5,161**	4,829
Accrued pension costs	**16,158**	13,675
Other	**10,089**	5,441
Total deferred tax assets	**108,552**	99,421
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**230,437**	203,762
Regulatory matters	**34,840**	25,325
Other	**---**	629
Total deferred tax liabilities	**265,277**	229,716
Net deferred income tax liability	**$ (156,725)**	$ (130,295)

As of December 31, 2014 and 2013, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2013, to December 31, 2014, to deferred income tax expense:

	2014
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 26,430**
Regulatory matters	**(2,763)**
Deferred income tax expense for the period	**$ 23,667**

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	**2014**		2013	
	Amount	%	Amount	%
		(Dollars in thousands)		
Computed tax at federal statutory rate	**$ 9,351**	**35.0**	$ 13,247	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	**842**	**3.1**	493	1.3
Resolution of tax matters and uncertain tax positions	**(1,444)**	**(5.4)**	(978)	(2.6)
AFUDC equity	**(636)**	**(2.4)**	---	---
Amortization of deferral of investment tax credit	**(331)**	**(1.2)**	241	0.6
Flow-through	**(224)**	**(0.8)**	(84)	(0.2)
Other	**(586)**	**(2.2)**	(123)	(0.3)
Total income tax expense	**$ 6,972**	**26.1**	$ 12,796	33.8

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. The Company is no longer subject to U.S. federal or state income tax examinations by tax authorities for years ending prior to 2007. The Company and the Internal Revenue Service have agreed to a settlement for the 2007 through 2009 tax years.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2014	2013
	(In thousands)	
Balance at beginning of year	**$ 2,559**	$ 2,559
Additions for tax positions of prior years	**---**	---
Settlements	**(2,559)**	---
Balance at end of year	**$ ---**	$ 2,559

Included in the balance of unrecognized tax benefits at December 31, 2013 was $1.1 million of tax positions for which the ultimate deductibility was highly certain but for which there was uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not have affected the annual effective tax rate but would have accelerated the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would have affected the effective tax rate was $1.8 million, including approximately $343,000 for the payment of interest and penalties at December 31, 2013.

For the years ended December 31, 2014 and 2013, the Company recognized approximately $103,000 and $77,000, respectively, in interest expense and $7,000 in penalties for the year ended December 31, 2014, related to unrecognized tax benefits. The Company recognized interest income of approximately $15,000 and $152,000 for the years ended December 31, 2014 and 2013, respectively. The Company had accrued liabilities of approximately $453,000 and $477,000 at December 31, 2014 and 2013, respectively, for the payment of interest.

NOTE 8 – EMPLOYEE BENEFIT PLANS

Pension and other postretirement benefit plans

The Company has a noncontributory defined benefit pension plan and other postretirement benefit plans for certain eligible employees. Effective October 1, 2003, Cascade amended the defined pension plan so that no new salaried participants will be added to the plan and no additional benefits will accrue for existing salaried participants. Effective January 1, 2007, the defined pension plan was amended so no new operational union employees would be added to the plan and eligible existing union participants would accrue a benefit at an annual rate of $107 per year. Effective September 30, 2012, Cascade's pension service accrual credit for union employees ceased. The Company's pension assets are included in MDU's master trust. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at Cascade and Intermountain. Current employees at Intermountain, and those hired before June 1, 1992 at Cascade, who had attained age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees at Intermountain hired after December 31, 2009, and employees at Cascade hired after June 1, 1992, will not be eligible for retiree medical benefits.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage was replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through an exchange.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2014 and 2013

Changes in benefit obligation and plan assets for the years ended December 31, 2014 and 2013 and amounts recognized in the Consolidated Balance Sheets at December 31, 2014 and 2013, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 81,928**	$ 92,987	**$ 18,923**	$ 23,834
Service cost	**---**	---	**188**	221
Interest cost	**3,620**	3,297	**804**	743
Plan participants' contributions	**---**	---	**406**	440
Actuarial (gain) loss	**16,595**	(10,090)	**3,563**	(4,513)
Benefits paid	**(4,354)**	(4,266)	**(1,872)**	(1,802)
Benefit obligation at end of year	**97,789**	81,928	**22,012**	18,923
Change in net plan assets:				
Fair value of plan assets at beginning of year	**68,987**	62,714	**20,458**	17,780
Actual gain on plan assets	**5,051**	7,339	**1,796**	3,318
Employer contribution	**3,289**	3,200	**676**	722
Plan participants' contributions	**---**	---	**406**	440
Benefits paid	**(4,354)**	(4,266)	**(1,872)**	(1,802)
Fair value of net plan assets at end of year	**72,973**	68,987	**21,464**	20,458
Funded status – over (under)	**$ (24,816)**	$ (12,941)	**$ (548)**	$ 1,535
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	$ ---	$ ---	$ ---	$ 1,535
Other liabilities (noncurrent)	**(24,816)**	(12,941)	**(548)**	---
Net amount recognized	**$ (24,816)**	$ (12,941)	**$ (548)**	$ 1,535
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 45,452**	$ 30,647	**$ 7,253**	$ 4,629
Prior service credit	**---**	---	**(2,018)**	(2,196)
Total	**$ 45,452**	$ 30,647	**$ 5,235**	$ 2,433

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Amounts recognized in regulatory assets (liabilities) in the above table are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities) see Note 3.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the average life expectancy of plan participants. The market-related value of assets is determined using a five-year average of assets.

The pension plan has accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2014	2013
	(In thousands)	
Projected benefit obligation	**$ 97,789**	$81,928
Accumulated benefit obligation	**$ 97,789**	$81,928
Fair value of plan assets	**$ 72,973**	$68,987

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 188**	$ 221
Interest cost	**3,620**	3,297	**804**	743
Expected return on assets	**(4,292)**	(4,072)	**(1,189)**	(1,026)
Amortization of prior service credit	**---**	---	**(178)**	(242)
Recognized net actuarial loss	**1,031**	1,404	**332**	906
Net periodic benefit cost (credit)	**359**	629	**(43)**	602
Other changes in plan assets and benefit obligations recognized in regulatory assets (liabilities):				
Net (gain) loss	**15,836**	(13,357)	**2,956**	(6,805)
Amortization of actuarial loss	**(1,031)**	(1,404)	**(332)**	(906)
Amortization of prior service credit	**---**	---	**178**	242
Total recognized in regulatory assets (liabilities)	**14,805**	(14,761)	**2,802**	(7,469)
Total recognized in net periodic benefit cost and regulatory assets (liabilities)	**$ 15,164**	$ (14,132)	**$ 2,759**	$ (6,867)

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets (liabilities) into net periodic benefit cost in 2015 is $1.4 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets (liabilities) into net periodic benefit cost in 2015 are $620,000 and $156,000, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
Discount rate	**3.73%**	4.56%	**3.73%**	4.49%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
Discount rate	**4.56%**	3.68%	**4.49%**	3.65%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2014, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2014	2013
Health care trend rate assumed for next year	**6.5%**	7.0%
Health care cost trend rate – ultimate	**5.0%**	5.0%
Year in which ultimate trend rate achieved	**2017**	2017

The Company's other postretirement benefit plans include health care benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over six percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2014:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 83	$ (71)
Effect on postretirement benefit obligation	$ 1,860	$ (1,577)

The Company's pension assets are managed by 15 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's pension plan assets are determined using the market approach.

The carrying value of the pension plan’s Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high quality, short-term instruments of domestic and foreign issuers. There are no unfunded commitments related to this fund.

The estimated fair value of the pension plan’s Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the pension plan’s Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. Units of these funds can be redeemed on a daily basis at their net asset value and have no redemption restrictions. There are no unfunded commitments related to these funds.

The estimated fair value of the pension plan’s Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data.

The estimated fair value of the pension plan’s Level 1 U.S. Government securities is valued based on quoted prices on an active market.

The estimated fair value of the pension plan’s Level 2 U.S. Government securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2014 and 2013, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plan assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
		(In thousands)		
Assets:				
Cash equivalents	$ ---	$ 1,160	$ ---	$ 1,160
Equity securities:				
U.S. companies	8,047	---	---	8,047
International companies	1,069	---	---	1,069
Collective and mutual funds*	27,265	15,949	---	43,214
Corporate bonds	---	12,247		12,247
Municipal bonds	---	2,154	---	2,154
U.S. Government securities	3,089	1,410	---	4,499
Total assets measured at fair value	$ 39,470	$ 32,920	$ ---	$ 72,390

* *Collective and mutual funds invest approximately 13 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Government securities, 23 percent in corporate bonds, 33 percent in common stock of international companies and 18 percent in other investments.*

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Cash equivalents	$ 525	$ 1,938	$ ---	$ 2,463
Equity securities:				
U.S. companies	12,897	---	---	12,897
International companies	8,125	---	---	8,125
Collective and mutual funds*	23,954	8,752	---	32,706
Corporate bonds	---	8,802		8,802
Municipal bonds	---	1,558	---	1,558
U.S. Government securities	1,543	893	---	2,436
Total assets measured at fair value	$ 47,044	$ 21,943	$ ---	$ 68,987

* *Collective and mutual funds invest approximately 11 percent in common stock of mid-cap U.S. companies, 19 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Government securities, 27 percent in corporate bonds, 13 percent in common stock of international companies and 18 percent in other investments.*

The estimated fair values of the Company's other postretirement benefit plans' assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to this fund.

The estimated fair value of the other postretirement benefit plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the other postretirement benefit plans' Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2014 and 2013, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 543	$ ---	$ 543
Equity securities:				
U.S. companies	1,223	---	---	1,223
International companies	25	---	---	25
Insurance contract*	70	19,603	---	19,673
Total assets measured at fair value	$ 1,318	$ 20,146	$ ---	$ 21,464

** The insurance contract invests approximately 54 percent in common stock of large-cap U.S. companies, 11 percent in U.S. Government securities, 10 percent in mortgage-backed securities, 10 percent in corporate bonds and 15 percent in other investments.*

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
			(In thousands)	
Assets:				
Cash equivalents	$ 229	$ 336	$ ---	$ 565
Equity securities:				
U.S. companies	1,406	---	---	1,406
International companies	221	---	---	221
Insurance contract*	---	18,266	---	18,266
Total assets measured at fair value	$ 1,856	$ 18,602	$ ---	$ 20,458

** The insurance contract invests approximately 55 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Government securities, 8 percent in mortgage-backed securities, 8 percent in common stock of mid-cap U.S. companies, 9 percent in corporate bonds and 8 percent in other investments.*

The Company expects to contribute approximately $915,000 to its defined benefit pension plan and approximately $25,000 to its postretirement benefit plans in 2015.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2015	$ 4,412	$ 1,320	$ 4
2016	4,528	1,313	4
2017	4,667	1,331	3
2018	4,854	1,319	3
2019	4,993	1,277	3
2020-2024	26,802	6,214	8

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans at Cascade and Intermountain for certain executive officers. Cascade’s plan provides for defined benefit payments following the employee's retirement or to their beneficiaries upon death for up to a 10-year period, plus the surviving spouse is entitled to receive a monthly benefit for life equal to one-half of the benefit the participant was entitled to before death. Effective October 1, 2003, the plan was amended so that no new participants will be added to the plan and no additional benefits will accrue for existing participants. Intermountain's plan provides for defined benefit payments following the employee's retirement until death for a minimum of a 20-year period or to their beneficiaries upon pre-retirement death for a 10-year period equal to twice the benefit the participant was entitled to before death. The Company's net periodic benefit cost for these plans was $1.1 million and $1.2 million in 2014 and 2013, respectively. The total projected benefit obligation for these plans was $15.7 million and $14.0 million at December 31, 2014 and 2013, respectively. The accumulated benefit obligations for these plans were $15.7 million and $13.9 million at December 31, 2014 and 2013, respectively. A weighted average discount rate of 3.5 percent and 4.3 percent at December 31, 2014 and 2013, respectively, and a rate of compensation increase of 4.0 percent at both December 31, 2014 and 2013, were used to determine benefit obligations. A discount rate of 4.3 percent and 3.4 percent for the years ended December 31, 2014 and 2013, respectively, and a rate of compensation increase of 4.0 percent and 3.0 percent for the years ended December 31, 2014 and 2013, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $927,000 in 2015; $1.0 million in 2016; $1.0 million in 2017; $1.1 million in 2018; $1.1 million in 2019; and $4.8 million for the years 2020 through 2024.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2014 and 2013 were $15,000 and $5,000, respectively.

The Company had investments of $10.1 million at both December 31, 2014 and 2013, consisting of equity securities of $2.5 million for both years, life insurance carried on plan participants (payable upon the employee's death) of $6.9 million and $6.7 million, respectively, and other investments of $621,000 and $934,000, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees and the costs incurred by the Company under these plans were $3.8 million in 2014 and $3.6 million in 2013.

Multiemployer plans
Intermountain contributes to a multiemployer defined benefit pension plan under the terms of a collective-bargaining agreement that covers its union-represented employees. The risks of participating in a multiemployer plan are different from a single-employer plan in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in the multiemployer plan, the Company may be required to pay the plan an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in this plan is outlined in the following table. The most recent Pension Protection Act zone status available in 2014 and 2013 is for the plan's year-end at December 31, 2013, and December 31, 2012, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2014	Pension Protection Act Zone Status 2013	FIP/RP Status Pending/ Implemented	Contributions **2014**	Contributions 2013	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2014	Green as of 5/31/2013	No	**$ 1,125**	$ 1,121	No	09/01/2013

Intermountain was listed in the Idaho Plumbers and Pipefitters Pension Plan’s Form 5500 as providing more than 5 percent of the total contributions as of the plan’s year-end of December 31, 2013 and 2012, respectively.

NOTE 9 – REGULATORY MATTERS

On December 31, 2012, the WUTC issued a policy statement for the accelerated replacement of natural gas pipeline facilities with elevated risk. On May 31, 2013, Cascade filed a pipeline replacement cost recovery mechanism with rate changes to coincide with its purchased gas costs adjustment. The WUTC approved recovery of $1.0 million of qualified pipeline replacement projects to be recovered from November 1, 2013 to October 31, 2014, as well as $2.0 million to be recovered from November 1, 2014 to October 31, 2015.

On March 13, 2013, the OPUC approved an extension of Cascade’s decoupling mechanism until December 31, 2015. As part of the decoupling mechanism extension, Cascade filed a rate case on March 31, 2015. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

On March 31, 2015, Cascade filed an application with the OPUC for a natural gas rate increase. Cascade requested a total increase of approximately $3.6 million annually or approximately 5.1 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities and the associated operation and maintenance expenses, depreciation and taxes associated with the increase in investment.

NOTE 10 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company is subject to claims and lawsuits arising out of its business. The Company accrues a liability for contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $14.3 million and $14.0 million for contingencies including litigation and environmental matters at December 31, 2014 and 2013, respectively, which include amounts that may have been accrued for matters discussed in Environmental matters within this note.

Regulatory matters

Natural Gas Distribution The WUTC on October 28, 2014, filed a complaint against Cascade, alleging various billing practice violations. The complaint stated allegations of 382,160 violations between June 1, 2012 and June 30, 2013, of misapplying Cascade's tariff; Cascade's billing practices violate Commission Order 05 in UG-060256; 1,511 violations of misapplying correct billing determinants in March 2013; and Cascade's tariff in regard to disconnect fees being inconsistent with state rules. WUTC staff is seeking relief including unspecified monetary penalties. On November 25, 2014, Cascade filed its response to the complaint admitting some and denying other of the alleged violations. This matter is pending before the WUTC. Management believes the outcome with respect to this issue will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon State Department of Environmental Quality released a record of decision in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.7 million for remediation of this site. In November 2012, Cascade filed a petition with the OPUC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until November 30, 2013. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013 and December 1, 2014.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.5 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. Cascade received insurance payments of $17,000 and $952,000 in 2014 and 2013, respectively, for the Eugene defense costs. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

The accruals related to these matters are reflected in regulatory assets. For more information, see Note 3.

Operating leases
The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2014, were $326,000 in 2015, $228,000 in 2016, $152,000 in 2017, $109,000 in 2018, $76,000 in 2019, and $309,000 thereafter. Rent expense was $373,000 and $402,000 for the years ended December 31, 2014 and 2013, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas supply and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 46 years. The commitments under these contracts as of December 31, 2014, were $266.3 million in 2015, $192.5 million in 2016, $110.2 million in 2017, $62.7 million in 2018, $62.0 million in 2019, and $824.0 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2014 and 2013, respectively, were approximately $252.0 million and $248.6 million.

Guarantees
Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study. At December 31, 2014, the fixed maximum amount guaranteed under this letter of credit was $2.2 million, which is scheduled to expire in 2015. There were no amounts outstanding under this letter of credit at December 31, 2014.

NOTE 11 – RELATED-PARTY TRANSACTIONS

MDU and Montana-Dakota provide and receive certain support services to/from the Company. The amount charged for services provided to the Company was $27.8 million and $27.6 million for the years ended December 31, 2014 and 2013, respectively and the amount charged for services received from the Company was $113,000 and $360,000 for the years ended December 31, 2014 and 2013, respectively.

The amounts included in the Consolidated Balance Sheets related to MDU and Montana-Dakota at December 31 were as follows:

	2014	2013
	(In thousands)	
Accounts receivable	**$ 7,628**	$ 108
Accounts payable	**2,543**	2,341
Dividend payable	**5,300**	5,300
Deferred charges and other assets - other	**3,294**	3,414
Deferred credits and other liabilities - other	**3,092**	1,348

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2014 and 2013, respectively, was $700,000 and $654,000, net of income taxes of $447,000 and $418,000, respectively. As of December 31, 2014, total remaining unrecognized compensation expense related to stock-based compensation was approximately $1.4 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	785,779,336
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	15,312,827
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	801,092,163
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	17,169,118
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	818,261,281
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	405,497,367
15	Net Utility Plant (Total of lines 13 and 14)	412,763,914
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(399,964,550)
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	
21	Amortization of Other Utility Plant	(5,532,817)
22	TOTAL In Service (Total of lines 18 thru 21)	(405,497,367)
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	TOTAL Leased to Others (Total of lines 24 and 25)	
27	Held for Future Use	
28	Depreciation	
29	Amortization	
30	TOTAL Held for Future Use (Total of lines 28 and 29)	
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	(405,497,367)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (continued)

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3		785,779,336		
4				
5				
6		15,312,827		
7				
8		801,092,163		
9				
10				
11		17,169,118		
12				
13		818,261,281		
14		405,497,367		
15		412,763,914		
16				
17				
18		(399,964,550)		
19				
20				
21		(5,532,817)		
22		(405,497,367)		
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33		(405,497,367)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.
4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c).Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d),

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT		
2	301 Organization	152,066	
3	302 Franchises and Consents	211,825	
4	303 Miscellaneous Intangible Plant	22,883,661	4,908,184
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	23,247,552	4,908,184
6	PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands		
9	325.2 Producing Leaseholds		
10	325.3 Gas Rights		
11	325.4 Rights-of-Way		
12	325.5 Other Land and Land Rights		
13	326 Gas Well Structures		
14	327 Field Compressor Station Structures		
15	328 Field Measuring and Regulating Station Equipment		
16	329 Other Structures		
17	330 Producing Gas Wells-Well Construction		
18	331 Producing Gas Wells-Well Equipment		
19	332 Field Lines		
20	333 Field Compressor Station Equipment		
21	334 Field Measuring and Regulating Station Equipment		
22	335 Drilling and Cleaning Equipment		
23	336 Purification Equipment		
24	337 Other Equipment		
25	338 Unsuccessful Exploration and Development Costs		
26	339 Asset Retirement Costs for Natural Gas Production and		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8		
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights		
30	341 Structures and Improvements		
31	342 Extraction and Refining Equipment		
32	343 Pipe Lines		
33	344 Extracted Products Storage Equipment		

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1				
2				152,066
3				211,825
4				27,791,845
5				28,155,736
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
34	345 Compressor Equipment		
35	346 Gas Measuring and Regulating Equipment		
36	347 Other Equipment		
37	348 Asset Retirement Costs for Products Extraction Plant		
38	TOTAL Products Extraction Plant (Enter Total of lines 29 thru 37)		
39	TOTAL Natural Gas Production Plant (Enter Total of lines 27 and		
40	Manufactured Gas Production Plant (Submit Supplementary		
41	TOTAL Production Plant (Enter Total of lines 39 and 40)		
42	NATURAL GAS STORAGE AND PROCESSING PLANT		
43	Underground Storage Plant		
44	350.1 Land		
45	350.2 Rights-of-Way		
46	351 Structures and Improvements		
47	352 Wells		
48	352.1 Storage Leaseholds and Rights		
49	352.2 Reservoirs		
50	352.3 Non-recoverable Natural Gas		
51	353 Lines		
52	354 Compressor Station Equipment		
53	355 Other Equipment		
54	356 Purification Equipment		
55	357 Other Equipment		
56	358 Asset Retirement Costs for Underground Storage Plant		
57	TOTAL Underground Storage Plant (Enter Total of lines 44 thru		
58	Other Storage Plant		
59	360 Land and Land Rights		
60	361 Structures and Improvements		
61	362 Gas Holders		
62	363 Purification Equipment		
63	363.1 Liquefaction Equipment		
64	363.2 Vaporizing Equipment		
65	363.3 Compressor Equipment		
66	363.4 Measuring and Regulating Equipment		
67	363.5 Other Equipment		
68	363.6 Asset Retirement Costs for Other Storage Plant		
69	TOTAL Other Storage Plant (Enter Total of lines 58 thru 68)		
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant		
71	364.1 Land and Land Rights		
72	364.2 Structures and Improvements		
73	364.3 LNG Processing Terminal Equipment		
74	364.4 LNG Transportation Equipment		
75	364.5 Measuring and Regulating Equipment		
76	364.6 Compressor Station Equipment		
77	364.7 Communications Equipment		
78	364.8 Other Equipment		
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas		
80	TOTAL Base Load Liquefied Nat'l Gas, Terminaling and Processing		

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
52				
53				
54				
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68				
69				
70				
71				
72				
73				
74				
75				
76				
77				
78				
79				
80				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
81	TOTAL Nat'l Gas Storage and Processing Plant (Total of lines 57,		
82	TRANSMISSION PLAN		
83	365.1 Land and Land Rights	224,536	
84	365.2 Rights-of-Way	1,026,089	
85	366 Structures and Improvements		
86	367 Mains	15,804,274	
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment	198,114	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant		
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	17,253,013	
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,509,635	
95	375 Structures and Improvements	1,458,788	
96	376 Mains	361,334,561	15,242,753
97	377 Compressor Station Equipment	2,000,731	
98	378 Measuring and Regulating Station Equipment-General	21,468,661	2,154,735
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	189,045,194	5,926,148
101	381 Meters	47,965,227	2,117,934
102	382 Meter Installations	30,029,638	215,933
103	383 House Regulators	9,922,839	343,906
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	8,890,422	315,564
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	48,962	
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	674,674,658	26,316,973
110	GENERAL PLANT		
111	389 Land and Land Rights	2,253,273	
112	390 Structures and Improvements	17,497,561	897,267
113	391 Office Furniture and Equipment	7,155,521	493,665
114	392 Transportation Equipment	11,694,815	1,247,796
115	393 Stores Equipment	55,776	
116	394 Tools, Shop, and Garage Equipment	5,799,513	640,140
117	395 Laboratory Equipment	138,043	
118	396 Power Operated Equipment	2,916,563	1,829,937
119	397 Communication Equipment	5,232,371	180,623
120	398 Miscellaneous Equipment	38,881	30,360
121	Subtotal (Enter Total of lines 111 thru 120)	52,782,317	5,319,788
122	399 Other Tangible Property		
123	399.1 Asset Retirement Costs for General Plant		
124	TOTAL General Plant (Enter Total of lines 121, 122 and 123)	52,782,317	5,319,788
125	TOTAL (Accounts 101 and 106)	767,957,540	36,544,945
126	Gas Plant Purchased (See Instruction 8)		
127	(Less) Gas Plant Sold (See Instruction 8)		
128	Experimental Gas Plant Unclassified		
129	TOTAL Gas Plant In Service (Enter Total of lines 125 thru 128)	767,957,540	36,544,945

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
81				
82				
83				224,536
84				1,026,089
85				
86				15,804,274
87				
88	5,814			192,300
89				
90				
91				
92	5,814			17,247,199
93				
94	20,982			2,488,653
95				1,458,788
96	429,264			376,148,050
97				2,000,731
98	12,323			23,611,073
99				
100	261,370			194,709,972
101				50,083,161
102	7,461			30,238,110
103	96,405			10,170,340
104				
105	6,433			9,199,553
106				
107				
108				48,962
109	834,238			700,157,393
110				
111				2,253,273
112				18,394,828
113	663,717			6,985,469
114	826,064			12,116,547
115	(11,149)			66,925
116	(52,469)			6,492,122
117	11,885			126,158
118	1,148,619			3,597,881
119	(10,716)			5,423,710
120	(5,681)			74,922
121	2,570,270			55,531,835
122				
123				
124	2,570,270			55,531,835
125	3,410,322			801,092,163
126				
127				
128				
129	3,410,322			801,092,163

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Property and Capacity Leased from Others

1. Report below the information called for concerning gas property and capacity leased from others for gas operations.
2. For all leases in which the average annual lease payment over the initial term of the lease exceeds $500,000, describe in column (c), if applicable: the property or capacity leased. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Property and Capacity Leased to Others

1. For all leases in which the average lease income over the initial term of the lease exceeds $500,000 provide in column (c), a description of each facility or leased capacity that is classified as gas plant in service, and is leased to others for gas operations.
2. In column (d) provide the lease payments received from others.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Plant Held for Future Use (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $1,000,000 or more. Group other items of property held for future use.
2. For property having an original cost of $1,000,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	**Total**			

Construction Work in Progress-Gas (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (Account 107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (less than $1,000,000) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	MN - Hanford/DOE Transmission Main	4,001,142	
2	Bellingham Gate Upgrade	1,917,408	
3	Southridge Gate Station	1,508,137	
4	Purchase GMS System	1,174,392	
5	Baker City Office Purchase	1,167,083	
6			
7			
8	Minor distribution system/general Plant projects each under		
9	$1 million	7,400,956	
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45	**Total**	**17,169,118**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Non-Traditional Rate Treatment Afforded New Projects

1. The Commission's Certificate Policy Statement provides a threshold requirement for existing pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. See Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC P61,227 (1999); order clarifying policy, 90 FERC P61,128 (2000); order clarifying policy, 92 FERC P61,094 (2000) (Policy Statement). In column a, list the name of the facility granted non-traditional rate treatment.
2. In column b, list the CP Docket Number where the Commission authorized the facility.
3. In column c, indicate the type of rate treatment approved by the Commission (e.g. incremental, at risk)
4. In column d, list the amount in Account 101, Gas Plant in Service, associated with the facility.
5. In column e, list the amount in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant, associated with the facility.

Line No.	Name of Facility (a)	CP Docket No. (b)	Type of Rate Treatment (c)	Gas Plant in Service (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Non-Traditional Rate Treatment Afforded New Projects (continued)

6. In column f, list the amount in Account 190, Accumulated Deferred Income Tax; Account 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account 282, Accumulated Deferred Income Taxes – Other Property; Account 283, Accumulated Deferred Income Taxes – Other, associated with the facility.
7. In column g, report the total amount included in the gas operations expense accounts during the year related to the facility (Account 401, Operation Expense).
8. In column h, report the total amount included in the gas maintenance expense accounts during the year related to the facility.
9. In column i, report the amount of depreciation expense accrued on the facility during the year.
10. In column j, list any other expenses(including taxes) allocated to the facility.
11. In column k, report the incremental revenues associated with the facility.
12. Identify the volumes received and used for any incremental project that has a separate fuel rate for that project.
13. Provide the total amounts for each column.

Line No.	Accumulated Depreciation (e)	Accumulated Deferred Income Taxes (f)	Operating Expense (g)	Maintenance Expense (h)	Depreciation Expense (i)	Other Expenses (including taxes) (j)	Incremental Revenues (k)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
	(1) X An Original	(Mo, Da, Yr)	
Cascade Natural Gas Corporation	(2) _ A Resubmission	12/31/2014	2014/Q4

General Description of Construction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

1. Engineering & Supervision and General & Administrative overhead:

Engineer & Supervision (ES) overhead consists of employees' time in preparation of work orders, mapping, detrmining feasibility and other Engineering/construction based supervisory costs related to new construction which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

General & Administrative (GA) overhead consists of employees' time in processing A/P, A/R, receiving orders, and other administrative functions which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

Both ES & GA (ES/GA) are accumulated in pools from which a portion is allocated each month. The allocation is based on a rate determined by the Fixed Assets Analyst and approved by the Manager of General & Asset Accounting which is then applied to the current month activity for all applicable work orders to determine how much should be transferred from the ES/GA pools to the affected work orders. This is accomplished via a system (PowerPlant) batch operation. An applicable work order is one that is capital installation/purchase, and not a preliminary survey or investigative in nature. Note that purchase projects only receive GA overhead, not ES. Construction projects receive both.

2. ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION (AFUDC)

The formula on page 218a is used.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

General Description of Construction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.
2. Identify, in a footnote, the specific entity used as the source for the capital structure figures.
3. Indicate, in a footnote, if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ration (percent) (c)	Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S 5,143,621		
	(2) Short-Term Interest			s 3.05
	(3) Long-Term Debt	D 161,786,857	49.50	d 5.72
	(4) Preferred Stock	P		p
	(5) Common Equity	C 164,988,681	50.50	c 10.00
	(6) Total Capitalization	326,775,538	100.00	
	(7) Average Construction Work In Progress Balance	W 14,267,376		

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] 2.91

3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))] 3.23

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 2.87

b. Rate for Other Funds - 3.19

Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 10, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	(382,583,084)	(382,583,084)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(19,613,636)	(19,613,636)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(1,062,771)	(1,062,771)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(738)	(738)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(20,677,145)	(20,677,145)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	3,410,322	3,410,322		
13	Cost of Removal	1,294,001	1,294,001		
14	Salvage (Credit)	1,213,745	1,213,745		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	3,490,578	3,490,578		
16	Other Debit or Credit Items (Describe) (footnote details):	(194,899)	(194,899)		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(399,964,550)	(399,964,550)		
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Productions-Manufactured Gas				
22	Production and Gathering-Natural Gas				
23	Products Extraction-Natural Gas				
24	Underground Gas Storage				
25	Other Storage Plant				
26	Base Load LNG Terminaling and Processing Plant				
27	Transmission	(10,931,121)	(10,931,121)		
28	Distribution	(363,333,180)	(363,333,180)		
29	General	(25,700,249)	(25,700,249)		
30	TOTAL (Total of lines 21 thru 29)	(399,964,550)	(399,964,550)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Stored (Accounts 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, and 164.3)

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.
2. Report in column (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.
3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e., fixed asset method or inventory method).

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of					960,973	2,893,474		3,854,447
2	Gas Delivered to Storage						657,892		657,892
3	Gas Withdrawn from						2,667,396		2,667,396
4	Other Debits and Credits					(827,684)			(827,684)
5	Balance at End of Year					133,289	883,970		1,017,259
6	Dth					30,339	183,258		213,597
7	Amount Per Dth					4.3933	4.8236		4.7625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Investments (Account 123, 124, and 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments.
2. Provide a subheading for each account and list thereunder the information called for:

(a) Investment in Securities-List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments) state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes.

(b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances that are properly includable in Account 123. Include advances subject to current repayment in Account 145 and 146. With respect to each advance, show whether the advance is a note or open account.

Line No.	Description of Investment (a)	* (b)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (c)	Purchases or Additions During the Year (d)
1				
2	Account 124			
3	Oregon weatherization loans			
4	Customer Note Receivable			
5	SERP Plan Assets		10,056,109	447,187
6	SISP Plan Assets		39,460	21,173
7				
8				
9				
10				
11	Account 136			
12	Short-term deposits of cash in interest			
13	bearing accounts (cash management accts)			
14				
15	Short-term deposits of cash in interest			
16	bearing accounts (Exec Deferred Compensation)			
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

Investments (Account 123, 124, and 136) (continued)

List each note, giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.

3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnote state the name of pledges and purpose of the pledge.
4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.
5. Report in column (h) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (i) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (h).

Line No.	Sales or Other Dispositions During Year (e)	Principal Amount or No. of Shares at End of Year (f)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (g)	Revenues for Year (h)	Gain or Loss from Investment Disposed of (i)
1					
2					
3					
4					
5	512,186		9,991,110	447,187	
6			60,633	1,084	
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Investments in Subsidiary Companies (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h).
(a) Investment in Securities-List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6	CGC Resources books were dissolved 12/31/08, but the company			
7	continues for gas supply contracting purposes only.			
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Cost of Account 123.1 $**		**TOTAL**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Investments in Subsidiary Companies (Account 123.1) (continued)

4. Designate in a footnote, any securities, notes, or accounts that were pledged, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report in column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost), and the selling price thereof, not including interest adjustments includible in column (f).
8. Report on Line 40, column (a) the total cost of Account 123.1.

Line No.	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

PREPAYMENTS (ACCOUNT 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	126,563
2	Prepaid Rents	4,209,809
3	Prepaid Taxes	1,278,937
4	Prepaid Interest	
5	Miscellaneous Prepayments	
6	TOTAL	5,615,309

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2) (continued)

EXTRAORDINARY PROPERTY LOSSES (ACCOUNT 182.1)

Line No.	Description of Extraordinary Loss [include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Losses Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
7	None						
8							
9							
10							
11							
12							
13							
14							
15	**Total**						

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2) (continued)

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (ACCOUNT 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Charges (c)	Costs Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
16	None						
17							
18							
19							
20							
21							
22							
23							
24							
25							
26	**Total**						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Other Regulatory Assets (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1							
2	Miscellaneous						
3							
4							
5	OR Tax Rate Change	(402,477)	23,675	various			(378,802)
6							
7	Asset Retirement Obligation	539,036	35,710				574,746
8	(WA regulatory asset)						
9							
10	Asset Retirement Obligation	21,622	1,621				23,243
11	(OR regulatory asset)						
12							
13	SFAS 109 Regulatory Asset	161,543	632	various			162,175
14	(OR regulatory asset)						
15							
16	FAS 158 Regulatory Asset	35,732,423	16,613,526				52,345,949
17	(Total system asset)						
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40	**Total**	36,052,147	16,675,164		0	0	52,727,311

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Miscellaneous Deferred Debits (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	WA Conservation Programs	3,555,548	4,851,121	4800-4813	5,508,865	2,897,804
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant	14,071,601	1,328,214		375	15,399,440
5	Remediation					
6						
7	WA Gas Management Sharing Margin	(106,484)	23,670	4800-4813	3,430	(86,244)
8	(amortization period 11/10-present)			4890		
9						
10	WA Over-refunded Temporary Revenue	(3,008)	3,551		18,784	(18,241)
11	Credit					
12						
13	OR Conservation Programs	(2,088,148)	5,265,519	4800-4813	4,494,436	(1,317,065)
14	(amortization period 11/10-present)			4890		
15						
16	OR Eugene Manufactured Gas Plant	1,362,875	520,412		6,324	1,876,963
17	Remediation					
18						
19	OR Intervenor Funding	35,380	59,393	4800-4813	47,434	47,339
20	(amortization period 11/10-present)			4890		
21						
22	OR Over-refunded Temporary Revenue	3,075	3,456		3,617	2,914
23	Credit					
24						
25	I/C Asset - Net Benefit Funds	1,962,098			4,476	1,957,622
26						
27	Post Retirement FAS 158	1,020,693	1,719,423		1,538,941	1,201,175
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	**Total**	19,813,630	13,774,759		11,626,682	21,961,707

BLANK PAGE

[Next page is 234]

Accumulated Deferred Income Taxes (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric			
3	Gas	20,926,644	2,086,789	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	20,926,644	2,086,789	
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	20,926,644	2,086,789	
8	Classification of TOTAL			
9	Federal Income Tax	20,039,172	2,000,055	
10	State Income Tax	887,472	86,734	
11	Local Income Tax			

Accumulated Deferred Income Taxes (Account 190) (continued)

Line No.	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			see	(3,863,519)			22,703,374
4			footnote				
5				(3,863,519)			22,703,374
6							
7				(3,863,519)			22,703,374
8							
9				(3,700,339)			21,739,456
10				(163,180)			963,918
11							

Capital Stock (Accounts 201 and 204)

1. Report below the details called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common stock - not publicly traded	1,000	1.00	
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Capital Stock (Accounts 201 and 204)

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Outstanding per Bal. Sheet (total amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1						
2	1,000	1,000				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Capital Stock: Subscribed, Liability for Conversion, Premium on, and Installments Recieved on (Accts 202, 203, 205, 206, 207, and 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of year.
4. For Premium on Account 207, Capital Stock, designate with an asterisk in column (b), any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	* (b)	Number of Shares (c)	Amount (d)
1	Account 207			
2	Premium on Capital Stock - Common		1,000	152,703,952
3				
4	Represents excess received over $1.00 par value			
5	of common stock			
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**Total**		**1,000**	**152,703,952**

Other Paid-In Capital (Accounts 208-211)

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
(b) Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	**Total**	**0**

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
16	None	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
	TOTAL	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) _ A Resubmission	12/31/2014	2014/Q4

Securities Issued or Assumed and Securities Refunded or Retired During the Year

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Long-Term Debt (Accounts 221, 222, 223, and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)
1	Account 224			
2				
3	Other Long Term Debt:			
4	Medium Term Notes	09/15/1997	09/15/2027	20,000,000
5	Medium Term Notes	03/16/1999	03/16/2029	15,000,000
6	Insured Quarterly Notes	02/01/2005	02/01/2035	24,863,000
7	Notes	09/01/2005	09/01/2020	15,000,000
8	Senior Notes	03/08/2007	03/08/2037	40,000,000
9	Senior Notes (Series A)	08/23/2013	08/23/2025	25,000,000
10	Senior Notes (Series B)	08/23/2013	08/23/2028	25,000,000
11	Senior Notes (Series A)	11/24/2014	11/24/2044	12,500,000
12	Senior Notes (Series B)	11/24/2014	11/24/2054	12,500,000
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL**			189,863,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Long-Term Debt (Accounts 221, 222, 223, and 224)

5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.

7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Interest for Year Rate (in %) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1					
2					
3					
4	7.480	1,496,000			
5	7.100	1,064,700			
6	5.250	1,297,524			
7	5.210	781,500			
8	5.790	2,316,000			
9	4.110	999,235			
10	4.360	1,060,015			
11	4.090	51,125			
12	4.240	53,000			
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40		9,119,099			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.
2. Show premium amounts by enclosing the figures in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	Amortization Period Date From (d)	Amortization Period Date To (e)
1	Unamortized Debt Expense (Account 181)				
2					
3	Medium Term Notes 7.48%	20,000,000	201,406	09/15/1997	09/15/2027
4	Medium Term Notes 7.10%	15,000,000	151,056	03/16/1999	03/16/2029
5	Insured Quarterly Notes 5.25%	25,090,000	1,947,598	02/01/2005	02/01/2035
6	Notes 5.21%	15,000,000	238,755	09/01/2005	09/01/2020
7	Senior Notes 5.79%	40,000,000	232,781	03/08/2007	03/08/2037
8	Senior Notes (Series A) 4.11%	25,000,000	151,810	08/23/2013	08/23/2025
9	Senior Notes (Series B) 4.36%	25,000,000	151,810	08/23/2013	08/23/2028
10	Revolving Credit Agreement		207,500	07/09/2013	07/09/2018
11	Senior Notes (Series A) 4.09%	12,500,000	59,681	11/24/2014	11/24/2044
12	Senior Notes (Series B) 4.24%	12,500,000	59,681	11/24/2014	11/24/2054
13	Senior Notes (Series A) 4.09%		22,181	01/15/2015	01/15/2045
14	Senior Notes (Series B) 4.24%		22,181	01/15/2015	01/15/2055
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

5. Furnish in a footnote details regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.

7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-Credit.

Line No.	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1				
2				
3	92,031		6,713	85,318
4	76,366		5,035	71,331
5	1,370,719		65,014	1,305,705
6	106,180		16,177	90,003
7	180,055		7,770	172,285
8	144,990	802	12,611	133,181
9	146,033	802	10,089	136,746
10	186,750		41,500	145,250
11		59,681	332	59,349
12		59,681	249	59,432
13		22,181		22,181
14		22,181		22,181
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Unamortized Loss and Gain on Reacquired Debt (Accounts 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.
2. In column (c) show the principal amount of bonds or other long-term debt reacquired.
3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform Systems of Accounts.
4. Show loss amounts by enclosing the figures in parentheses.
5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt, or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal of Debt Reacquired (c)	Net Gain or Loss (d)	Balance at Beginning of Year (e)	Balance at End of Year (f)
1	Unamortized Loss on					
2	Reacquired Debt (Acct 189)					
3						
4						
5	7.50% Notes					
6	Due 11/15/2031 (1)	11/15/2001	39,729,000	(1,229,120)	949,154	908,183
7						
8	See footnote					
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Reconciliation of Reported Net Income with Taxable Income for Feder Income Taxes

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal Income Tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	12,035,057
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See footnote	3,096,239
6		
7		
8	TOTAL	3,096,239
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	35,305,931
11		
12		
13	TOTAL	35,305,931
14	Income Recorded on Books Not Included in Return	
15	Interest capitalized adj. (IRS>books)	(241,451)
16	AFUDC Equity	(67,145)
17		
18	TOTAL	(308,596)
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	(56,609,322)
21		
22		
23		
24		
25		
26	TOTAL	(56,609,322)
27	Federal Tax Net Income	(6,480,691)
28	Show Computation of Tax:	
29	Rate - 35.00%	
30	Estimated Tax Return Federal Income Tax	(2,268,242)
31	Adjustments:	
32	Difference between 12/31/13 accrual and tax return	(4,998,359)
33	Provision for Current Federal Income Tax (see footnote)	(7,266,601)
34	Oregon State Tax Calculation - (see footnote)	(408,487)
35		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to the portion of prepaid taxes charged to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)	Balance at Beg. of Year Taxes Accrued (b)	Balance at Beg. of Year Prepaid Taxes (c)
1	Income Tax		
2	Oregon Accrued	(15,827)	
3	Federal Accrued	(183,992)	
4	Fin 48 - current	1,403,254	
5	Gross Revenue		
6	Washington	420,347	
7	Oregon		
8	Dept of Energy - Oregon		27,061
9	City Franchise & Occupation		
10	Washington	1,801,678	
11	Oregon	802,551	
12	Property		
13	Washington	2,756,275	
14	Oregon		628,933
15	Payroll Taxes	79,746	
16	State Excise - Washington	2,235,566	
17			
18	Miscellaneous		
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
	TOTAL	9,299,598	655,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this
page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to the portion of prepaid taxes charged to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1, 409.1) (j)	Other Utility Dept. (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1				
2		(406,771)		(1,716)
3		(7,266,101)		(501)
4				
5				
6		484,369		
7		164,934		
8		56,355		
9				
10		10,167,054		
11		2,683,941		
12				
13		2,953,208		2,962
14		1,269,904		
15		2,093,289		
16		9,198,932		
17				
18		74,610		
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
	TOTAL	21,473,724		745

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged) (continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in columns (i) thru (p) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

Line No.	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (h)
1					
2	(408,487)	(154,800)			269,514
3	(7,287,194)	(5,681,081)	1,440,361		349,744
4	37,107		(1,440,361)		
5					
6	484,369	426,633		478,083	
7	164,934	164,934			
8	56,355	53,440			24,146
9					
10	10,167,054	10,231,030		1,737,702	
11	2,683,941	2,722,040		764,452	
12					
13	2,956,170	2,786,559		2,925,886	
14	1,269,904	1,276,505			635,534
15	2,288,327	2,256,123		111,950	
16	9,588,055	9,537,285		2,286,336	
17					
18	74,610	74,610			
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
TOTAL	22,075,145	23,693,278		8,304,409	1,278,938

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged) (continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in columns (i) thru (p) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)
1					
2					1.52
3				(20,592)	
4				37,107	
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15				195,038	
16				389,123	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
TOTAL				600,676	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Miscellaneous Current and Accrued Liabilities (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	Accrued Paid Time Off Liability	1,683,303
2	Accrued 401k Defined Contributions	952,342
3	Wages Payable	949,133
4	Accounts Payable Accrual	946,290
5	Variable Pay Incentive Contribution	692,354
6	Pipeline Imbalances	593,147
7	Washington Low Income Assist Liability	589,265
8	SERP Defined Contributions	485,309
9	Conservation Achievement Tariff	322,584
10	Oregon Weatherization Liability	304,245
11	Energy Tust of Oregon Liability	268,957
12	Professional Services (bank, accounting, legal)	256,181
13	Other Misc. Current Liabilities (aggregate)	129,272
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45	**Total**	**8,172,382**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	WA Deferred Gas Costs	(3,982,995)	805.1	34,571,292	30,008,130	(8,546,157)
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	1,644,450	805.1	10,482,183	8,460,440	(377,293)
5	(ammortization period 11/11-present)					
6						
7	OR Earning Sharing Liability	8,475	805.1	20,679	12,204	
8	(ammortization period 11/11-present)					
9						
10	SGL Deposit	168,945	134/228.4	24,135		144,810
11	Customer Unclaimed Credits	5,707	131	461	179	5,425
12	MDUR Interco NC Payable - FAS 158	727,819	228.3/182.		557,906	1,285,725
13	Pension Contribution	12,941,065	various	3,665,291	15,540,043	24,815,817
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45	**Total**	11,513,466		48,764,041	54,578,902	17,328,327

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Accumulated Deferred Income Taxes-Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric			
3	Gas	(84,106,817)	(11,635,316)	
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(84,106,817)	(11,635,316)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(84,106,817)	(11,635,316)	
8	Classification of TOTAL			
9	Federal Income Tax	(81,315,722)	(11,100,648)	
10	State Income Tax	(2,791,095)	(534,668)	
11	Local Income Tax			

Accumulated Deferred Income Taxes-Other Property (Account 282) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			182.3 &254	281,562	182.3 &254	677,561	(96,138,132)
4							
5				281,562		677,561	(96,138,132)
6							
7				281,562		677,561	(96,138,132)
8							
9			254	253,818	254	593,114	(92,755,666)
10			182.3	27,744	182.3	84,447	(3,382,466)
11							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Accumulated Deferred Income Taxes-Other (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(28,196,051)	(1,060,709)	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(28,196,051)	(1,060,709)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	(28,196,051)	(1,060,709)	
8	Classification of TOTAL			
9	Federal Income Tax	(26,635,990)	(1,006,406)	
10	State Income Tax	(1,560,061)	(54,303)	
11	Local Income Tax			

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report End of 2014/Q4

Accumulated Deferred Income Taxes-Other (Account 283) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			see	32,396	see	3,868,013	(33,092,377)
4			footnote		footnote		
5				32,396		3,868,013	(33,092,377)
6							
7				32,396		3,868,013	(33,092,377)
8							
9						3,704,832	(31,347,228)
10				32,396		163,181	(1,745,149)
11							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Other Regulatory Liabilities (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	SFAS 109 Regulatory Liability	3,692,243	282	569,047		221,962	3,345,158
2	Oregon Tax Rate Change	(56,037)	282			3,296	(52,741)
3	Regulatory Liability - Post Ret FAS 158	1,020,693	186	175,398			845,295
4	11/1/12 Consolidated Other Technical Adjustments	444	186	861		417	
5	11/12 Under-Refunded Temporary Revenue Credit	(3,044)	186				(3,044)
6	11/12 Under-Refunded Temporary Revenue Credit	(1,356)	186				(1,356)
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45	**Total**	4,652,943		745,306	0	225,675	4,133,312

BLANK PAGE

[Next page is 300]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Operating Revenues

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480 Residential Sales				
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartmental Sales				
6	485 Intracompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenues from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natural Gas				
14	491 Revenues from Natural Gas Proc. by Others				
15	492 Incidental Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartmental Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	TOTAL:				

Gas Operating Revenues

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	168,894,446	155,115,564	168,894,446	155,115,564	14,911,640	16,025,665
2	113,721,758	99,183,793	113,721,758	99,183,793	13,940,004	14,164,494
3						
4						
5						
6						
7						
8	1,138,977	1,275,841	1,138,977	1,275,841		
9						
10						
11	23,895,477	23,444,372	23,895,477	23,444,372	97,122,330	101,421,986
12						
13						
14						
15						
16	110,952	104,591	110,952	104,591		
17						
18	270,865	190,787	270,865	190,787		
19	308,032,475	279,314,948	308,032,475	279,314,948		
20						
21	308,032,475	279,314,948	308,032,475	279,314,948		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Revenues from Transporation of Gas of Others Through Gathering Facilities (Account 489.1)

1. Report revenues and Dth of gas delivered through gathering facilities by zone of receipt (i.e. state in which gas enters respondent's system).
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.

Line No.	Rate Schedule and Zone of Receipt (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Current Year (d)
1	N/A				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Revenues from Transporation of Gas of Others Through Gathering Facilities (Account 489.1)

3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e).
4. Delivered Dth of gas must not be adjusted for discounting.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Revenues from Transportation of Gas of Others Through Transmission Facilities (Account 489.2)

1. Report revenues and Dth of gas delivered by Zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, provide totals by rate schedule.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges for transportation and hub services, less revenues reflected in columns (b) through (e).

Line No.	Zone of Delivery, Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	N/A				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Revenues from Transportation of Gas of Others Through Transmission Facilities (Account 489.2)

4. Delivered Dth of gas must not be adjusted for discounting.
5. Each incremental rate schedule and each individually certificated rate schedule must be separately reported.
6. Where transportation services are bundled with storage services, report total revenues but only transportation Dth.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Revenues from Storing Gas of Others (Account 489.4)

1. Report revenues and Dth of gas withdrawn from storage by Rate Schedule and in total.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other revenues in columns (f) and (g) include reservation charges, deliverability charges, injection and withdrawal charges, less revenues reflected in columns (b) through (e).

Line No.	Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	N/A				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Revenues from Storing Gas of Others (Account 489.4)

4. Dth of gas withdrawn from storage must not be adjusted for discounting.
5. Where transportation services are bundled with storage services, report only Dth withdrawn from storage.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Other Gas Revenues (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Miscellaneous Sales	270,865
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
	Total	**270,865**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Discounted Rate Services and Negotiated Rate Services

1. In column b, report the revenues from discounted rate services.
2. In column c, report the volumes of discounted rate services.
3. In column d, report the revenues from negotiated rate services.
4. In column e, report the volumes of negotiated rate services.

Line No.	Account (a)	Discounted Rate Services Revenue (b)	Discounted Rate Services Volumes (c)	Negotiated Rate Services Revenue (d)	Negotiated Rate Services Volumes (e)
1	Account 489.1, Revenues from transportation of gas of others through gathering facilities.				
2	Account 489.2, Revenues from transportation of gas of others through transmission facilities.				
3	Account 489.4, Revenues from storing gas of others.				
4	Account 495, Other gas revenues.				
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
	Total				

Gas Operation and Maintenance Expenses

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)	0	0
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	0	0
8	751 Production Maps and Records	0	0
9	752 Gas Well Expenses	0	0
10	753 Field Lines Expenses	0	0
11	754 Field Compressor Station Expenses	0	0
12	755 Field Compressor Station Fuel and Power	0	0
13	756 Field Measuring and Regulating Station Expenses	0	0
14	757 Purification Expenses	0	0
15	758 Gas Well Royalties	0	0
16	759 Other Expenses	0	0
17	760 Rents	0	0
18	TOTAL Operation (Total of lines 7 thru 17)	0	0
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	0
21	762 Maintenance of Structures and Improvements	0	0
22	763 Maintenance of Producing Gas Wells	0	0
23	764 Maintenance of Field Lines	0	0
24	765 Maintenance of Field Compressor Station Equipment	0	0
25	766 Maintenance of Field Measuring and Regulating Station Equipment	0	0
26	767 Maintenance of Purification Equipment	0	0
27	768 Maintenance of Drilling and Cleaning Equipment	0	0
28	769 Maintenance of Other Equipment	0	0
29	TOTAL Maintenance (Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchased for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility-Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Total of lines 33 thru 46)	0	0
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Regulating Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	0	0
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	0
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
70	801 Natural Gas Field Line Purchases	0	0
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
72	803 Natural Gas Transmission Line Purchases	0	0
73	804 Natural Gas City Gate Purchases	184,357,615	176,604,343
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	9,992,807	26,394,383
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	174,364,808	150,209,960
78	806 Exchange Gas	0	0
79	Purchased Gas Expenses		
80	807.1 Well Expense-Purchased Gas	0	0
81	807.2 Operation of Purchased Gas Measuring Stations	0	0
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	0
83	807.4 Purchased Gas Calculations Expenses	0	0
84	807.5 Other Purchased Gas Expenses	0	0
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
86	808.1 Gas Withdrawn from Storage-Debit	5,944,340	4,182,942
87	(Less) 808.2 Gas Delivered to Storage-Credit	4,208,220	4,048,172
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	0	0
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	0	0
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	0	0
92	811 Gas Used for Products Extraction-Credit	0	0
93	812 Gas Used for Other Utility Operations-Credit	71,831	68,058
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	71,831	68,058
95	813 Other Gas Supply Expenses	412,374	374,039
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	176,441,471	150,650,711
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	176,441,471	150,650,711
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Total of lines of 101 thru 113)	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	TOTAL Maintenance (Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulating Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(less) 845.5 Wharfage Receipts-Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,693,423	1,781,876
205	871 Distribution Load Dispatching	748,375	504,809
206	872 Compressor Station Labor and Expenses	84,951	113,822
207	873 Compressor Station Fuel and Power	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses	4,096,066	4,386,187
209	875 Measuring and Regulating Station Expenses-General	933,813	776,853
210	876 Measuring and Regulating Station Expenses-Industrial	105,182	165,452
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,815,786	1,805,503
213	879 Customer Installations Expenses	1,412,842	1,375,909
214	880 Other Expenses	4,932,815	4,475,306
215	881 Rents	83,683	105,439
216	TOTAL Operation (Total of lines 204 thru 215)	15,906,936	15,491,156
217	Maintenance		
218	885 Maintenance Supervision and Engineering	288,325	384,799
219	886 Maintenance of Structures and Improvements	97,549	21,689
220	887 Maintenance of Mains	1,610,619	1,673,148
221	888 Maintenance of Compressor Station Equipment	17,713	9,053
222	889 Maintenance of Measuring and Regulating Station Equipment-General	361,741	509,229
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	58,992	63,985
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	1,794,453	1,425,748
226	893 Maintenance of Meters and House Regulators	1,376,570	1,261,481
227	894 Maintenance of Other Equipment	290,079	181,641
228	TOTAL Maintenance (Total of lines 218 thru 227)	5,896,041	5,530,773
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	21,802,977	21,021,929
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	26	25,965
233	902 Meter Reading Expenses	694,539	686,578
234	903 Customer Records and Collection Expenses	4,578,224	4,454,512

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	1,391,878	1,040,101
236	905 Miscellaneous Customer Accounts Expenses	5,647	9,220
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	6,670,314	6,216,376
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	1,276,116	1,932,560
242	909 Informational and Instructional Expenses	32,163	29,068
243	910 Miscellaneous Customer Service and Informational Expenses	269	0
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	1,308,548	1,961,628
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	9,917	7,755
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	9,917	7,755
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	6,944,474	6,297,212
255	921 Office Supplies and Expenses	5,568,194	5,056,018
256	(Less) 922 Administrative Expenses Transferred-Credit	550,892	540,949
257	923 Outside Services Employed	1,165,240	768,765
258	924 Property Insurance	68,879	78,247
259	925 Injuries and Damages	1,361,498	364,683
260	926 Employee Pensions and Benefits	6,236,886	5,021,331
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	0
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	55,670	106,011
265	930.2Miscellaneous General Expenses	554,335	687,930
266	931 Rents	1,277,061	1,304,714
267	TOTAL Operation (Total of lines 254 thru 266)	22,681,345	19,143,962
268	Maintenance		
269	932 Maintenance of General Plant	35,427	57,390
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	22,716,772	19,201,352
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	228,949,999	199,059,751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Exchange and Imbalance Transactions

1. Report below details by zone and rate schedule concerning the gas quantities and related dollar amount of imbalances associated with system balancing and no-notice service. Also, report certificated natural gas exchange transactions during the year. Provide subtotals for imbalance and no-notice quantities for exchanges. If respondent does not have separate zones, provide totals by rate schedule. Minor exchange transactions (less than 100,000 Dth) may be grouped.

Line No.	Zone/Rate Schedule (a)	Gas Received from Others Amount (b)	Gas Received from Others Dth (c)	Gas Delivered to Others Amount (d)	Gas Delivered to Others Dth (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	**Total**	0	0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Used in Utility Operations

1. Report below details of credits during the year to Accounts 810, 811, and 812.
2. If any natural gas was used by the respondent for which a charge was not made to the appropriate operating expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit					
2	811 Gas Used for Products Extraction - Credit					
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others					
5	812 Gas Used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses.)					
6						
7	Gas Used for Other Utility Operations	812	17,079	71,831		
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	**Total**		17,079	71,831		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Transmission and Compression of Gas by Others (Account 858)

1. Report below details concerning gas transported or compressed for respondent by others equalling more than 1,000,000 Dth and amounts of payments for such services during the year. Minor items (less than 1,000,000) Dth may be grouped. Also, include in column (c) amounts paid as transition costs to an upstream pipeline.
2. In column (a) give name of companies, points of delivery and receipt of gas. Designate points of delivery and receipt so that they can be identified readily on a map of respondent's pipeline system.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Company and Description of Service Performed (a)	* (b)	Amount of Payment (in dollars) (c)	Dth of Gas Delivered (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Other Gas Supply Expenses (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1	Labor Expenses and applicable overhead charges	477,802
2	Software Maintenance	20,781
3	Airfare and related costs	8,012
4	Lodging	7,396
5	Meals	3,084
6	Training Meetings and Materials	1,277
7	Vehicle Mileage	623
8	Cell Phone	619
9	Office Supplies	486
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	520,080

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Miscellaneous General Expenses (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses.
2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items of so grouped is shown.

Line No.	Description (a)	Amount (in dollars) (b)
1	Industry association dues.	145,116
2	Experimental and general research expenses.	
	a. Gas Research Institute (GRI)	
	b. Other	
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer	
	agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	
4	Other expenses	
5	Bank and Other Finance Fees (paid to Bank of New York, and MDU for CNGC's share of	
6	corporate banking fees)	283,619
7	Director's Fees (paid to MDU for CNGC's share of director's expenses)	121,546
8	Miscellaneous under $250,000 (4 items)	4,054
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	554,335

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant				2,172,996
2	Production plant, manufactured gas				
3	Production and gathering plant, natural gas				
4	Products extraction plant				
5	Underground gas storage plant				
6	Other storage plant				
7	Base load LNG terminaling and processing plant				
8	Transmission plant	322,015			
9	Distribution plant	18,323,540			
10	General plant	968,081			
11	Common plant-gas				
12	TOTAL	19,613,636			2,172,996

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments) (continued)

obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1			2,172,996	Intangible plant
2				Production plant, manufactured gas
3				Production and gathering plant, natural gas
4				Products extraction plant
5				Underground gas storage plant
6				Other storage plant
7				Base load LNG terminaling and processing plant
8			322,015	Transmission plant
9			18,323,540	Distribution plant
10			968,081	General plant
11				Common plant-gas
12			21,786,632	TOTAL

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments) (continued)

4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (percent) (c)
1	Production and Gathering Plant		
2	Offshore (footnote details)		
3	Onshore (footnote details)		
4	Underground Gas Storage Plant (footnote details)		
5	Transmission Plant		
6	Offshore (footnote details)		
7	Onshore (footnote details)		
8	General Plant (footnote details)		
9	See footnote		
10			
11			
12			
13			
14			
15			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

(a) Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) - Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	(a) Miscellaneous Amortization (Account 425)	
2		
3	(b) Miscellaneous Income Deductions (Account 426)	
4	Donations (Account 426.1)	237,332
5	Life Insurance (Account 426.2)	
6	Penalties (Account 426.3)	5,016
7	Expenditures for Certain Civic, Political and Related Activies	
8	(Account 426.4)	117,835
9	Other Deductions (Account 426.5)	350
10	Total Miscellaneous Income Deductions (Account 426)	360,533
11		
12	(c) Interest on Debt to Associated Companies (Account 430)	
13		
14	(d) Other Interest Expense (Account 431)	
15	Description Interest Rate	
16	Customer Deposits Various	2,029
17	Deferral Accounts-WA FERC Interest Rate	217,014
18	Deferral Accounts-OR ***	
19	Interest on Short-Term Debt Various	137,887
20	Other Various	69,867
21	Total Other Interest Expense (Acount 431)	426,797
22		
23	***Accounts not amortizing - 8.07% (Overall rate of return granted in the last	
24	Oregon general rate filing); Accounts amortizing - 1.77%	
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	**Total**				

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2014	Year/Period of Report End of 2014/Q4

Regulatory Commission Expenses (Account 928)

3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA).
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Employee Pensions and Benefits (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits.

Line No.	Expense (a)	Amount (b)
1	Pensions – defined benefit plans	287,890
2	Pensions – other	2,254,602
3	Post-retirement benefits other than pensions (PBOP)	91,575
4	Post- employment benefit plans	444,772
5	Other (Specify)	
6	Medical/Dental	2,808,428
7	Various	355,016
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
	Total	**6,242,283**

BLANK PAGE

[Next page is 354]

Distribution of Salaries and Wages

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production				
4	Transmission				
5	Distribution				
6	Customer Accounts				
7	Customer Service and Informational				
8	Sales				
9	Administrative and General				
10	TOTAL Operation (Total of lines 3 thru 9)				
11	Maintenance				
12	Production				
13	Transmission				
14	Distribution				
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)				
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)				
19	Transmission (Total of lines 4 and 13)				
20	Distribution (Total of lines 5 and 14)				
21	Customer Accounts (line 6)				
22	Customer Service and Informational (line 7)				
23	Sales (line 8)				
24	Administrative and General (Total of lines 9 and 15)				
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)				
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply				
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution	10,366,396			10,366,396
34	Customer Accounts	3,805,848			3,805,848
35	Customer Service and Informational	1,287			1,287
36	Sales				
37	Administrative and General	5,376,909			5,376,909
38	TOTAL Operation (Total of lines 28 thru 37)	19,550,440			19,550,440
39	Maintenance				
40	Production - Manufactured Gas				
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission				
45	Distribution	3,497,030			3,497,030

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Distribution of Salaries and Wages (continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	3,497,030			3,497,030
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)				
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	13,863,426			13,863,426
56	Customer Accounts (Total of line 34)	3,805,848			3,805,848
57	Customer Service and Informational (Total of line 35)	1,287			1,287
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	5,376,909			5,376,909
60	Total Operation and Maintenance (Total of lines 50 thru 59)	23,047,470			23,047,470
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	23,047,470			23,047,470
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	6,064,640			6,064,640
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	6,064,640			6,064,640
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	214,515			214,515
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	214,515			214,515
75	Other Accounts (Specify) (footnote details)	693,738			693,738
76	TOTAL Other Accounts	693,738			693,738
77	TOTAL SALARIES AND WAGES	30,020,363			30,020,363

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising,labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.
 (a) Name of person or organization rendering services.
 (b) Total charges for the year.
2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned services.
4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	Northwest Metal Fabrication & Pipe, Inc.	6,150,125
2	Snelson Companies, Inc.	3,510,689
3	Michels Corporation	1,774,210
4	MRES Consulting, LTD	1,277,223
5	Sungard Energy Sytems	750,022
6	Northwest Pipeline GP	703,679
7	Surveys & Analysis, Inc.	502,515
8	Day Wireless Systems, Inc.	410,395
9	Potelco, Inc.	404,665
10	Prosource Tech, Inc.	375,898
11	John & Marsha Hammond	333,012
12	Anchor QEA	304,504
13	Express Employement Professional	278,257
14	Other	7,902,401
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35	Total	24,677,595

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2		IGC/MDU/MDU Resources	107	3,249,124
3		IGC/MDU/MDU Resources	426.1	13,109
4		IGC/MDU/MDU Resources	426.4	18
5		IGC/MDU/MDU Resources	813	225,034
6		IGC/MDU/MDU Resources	875	211,075
7		IGC/MDU/MDU Resources	880	689,618
8		IGC/MDU/MDU Resources	902	149,764
9		IGC/MDU/MDU Resources	903	4,195,172
10		IGC/MDU/MDU Resources	909	19,872
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Goods or Services Provided for Affiliated Company			
21		IGC/MDU/MDU Resources	920	4,017,677
22		IGC/MDU/MDU Resources	921	3,449,588
23		IGC/MDU/MDU Resources	922	(3,127)
24		IGC/MDU/MDU Resources	923	275,496
25		IGC/MDU/MDU Resources	925	2,844
26		IGC/MDU/MDU Resources	926	162,201
27		IGC/MDU/MDU Resources	930.1	19,830
28		IGC/MDU/MDU Resources	930.2	142,250
29		IGC/MDU/MDU Resources	931	1,222,467
30		IGC/MDU/MDU Resources	Various	134,703
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	Total			18,176,715

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Compressor Stations

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, products extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.
2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned.

Line No.	Name of Station and Location (a)	Number of Units at Station (b)	Certificated Horsepower for Each Station (c)	Plant Cost (d)
1	Compressor Station at Burlington, WA	1	1,350	2,000,731
2	Placed in Service: August 2001			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Compressor Stations

Designate any station that was not operated during the past year. State in a footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are contemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year and show in a footnote each unit's size and the date the unit was placed in operation.

3. For column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or power.

Line No.	Expenses (except depreciation and taxes) Fuel (e)	Expenses (except depreciation and taxes) Power (f)	Expenses (except depreciation and taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station in kWh (i)	Operational Data Total Compressor Hours of Operation During Year (j)	Operational Data Number of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1	10,527		118,345				1	
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Storage Projects

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January			
3	February			
4	March			
5	April			
6	May			
7	June			
8	July			
9	August			
10	September			
11	October			
12	November			
13	December			
14	TOTAL (Total of lines 2 thru 13)			
15	Gas Withdrawn from Storage			
16	January			
17	February			
18	March			
19	April			
20	May			
21	June			
22	July			
23	August			
24	September			
25	October			
26	November			
27	December			
28	TOTAL (Total of lines 16 thru 27)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	
2	Cushion Gas (Including Native Gas)	
3	Total Gas in Reservoir (Total of line 1 and 2)	
4	Certificated Storage Capacity	
5	Number of Injection - Withdrawal Wells	
6	Number of Observation Wells	
7	Maximum Days' Withdrawal from Storage	
8	Date of Maximum Days' Withdrawal	
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	LNG Volume	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Transmission Lines

1. Report below, by state, the total miles of transmission lines of each transmission system operated by respondent at end of year.
2. Report separately any lines held under a title other than full ownership. Designate such lines with an asterisk, in column (b) and in a footnote state the name of owner, or co-owner, nature of respondent's title, and percent ownership if jointly owned.
3. Report separately any line that was not operated during the past year. Enter in a footnote the details and state whether the book cost of such a line, or any portion thereof, has been retired in the books of account, or what disposition of the line and its book costs are contemplated.
4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
1	None		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Transmission System Peak Deliveries

1. Report below the total transmission system deliveries of gas (in Dth), excluding deliveries to storage, for the period of system peak deliveries indicated below, during the 12 months embracing the heating season overlapping the year's end for which this report is submitted. The season's peak normally will be reached before the due date of this report, April 30, which permits inclusion of the peak information required on this page. Add rows as necessary to report all data. Number additional rows 6.01, 6.02, etc.

Line No.	Description	Dth of Gas Delivered to Interstate Pipelines (b)	Dth of Gas Delivered to Others (c)	Total (b) + (c) (d)
	SECTION A: SINGLE DAY PEAK DELIVERIES			
1	Date:			
2	Volumes of Gas Transported			
3	No-Notice Transportation			
4	Other Firm Transportation			
5	Interruptible Transportation			
6	Other (Describe) (footnote details)			
7	TOTAL			
8	Volumes of gas Withdrawn form Storage under Storage Contract			
9	No-Notice Storage			
10	Other Firm Storage			
11	Interruptible Storage			
12	Other (Describe) (footnote details)			
13	TOTAL			
14	Other Operational Activities			
15	Gas Withdrawn from Storage for System Operations			
16	Reduction in Line Pack			
17	Other (Describe) (footnote details)			
18	TOTAL			
19	SECTION B: CONSECUTIVE THREE-DAY PEAK DELIVERIES			
20	Dates:			
21	Volumes of Gas Transported			
22	No-Notice Transportation			
23	Other Firm Transportation			
24	Interruptible Transportation			
25	Other (Describe) (footnote details)			
26	TOTAL			
27	Volumes of Gas Withdrawn from Storage under Storage Contract			
28	No-Notice Storage			
29	Other Firm Storage			
30	Interruptible Storage			
31	Other (Describe) (footnote details)			
32	TOTAL			
33	Other Operational Activities			
34	Gas Withdrawn from Storage for System Operations			
35	Reduction in Line Pack			
36	Other (Describe) (footnote details)			
37	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2014	End of 2014/Q4

Auxiliary Peaking Facilities

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery?
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales,transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

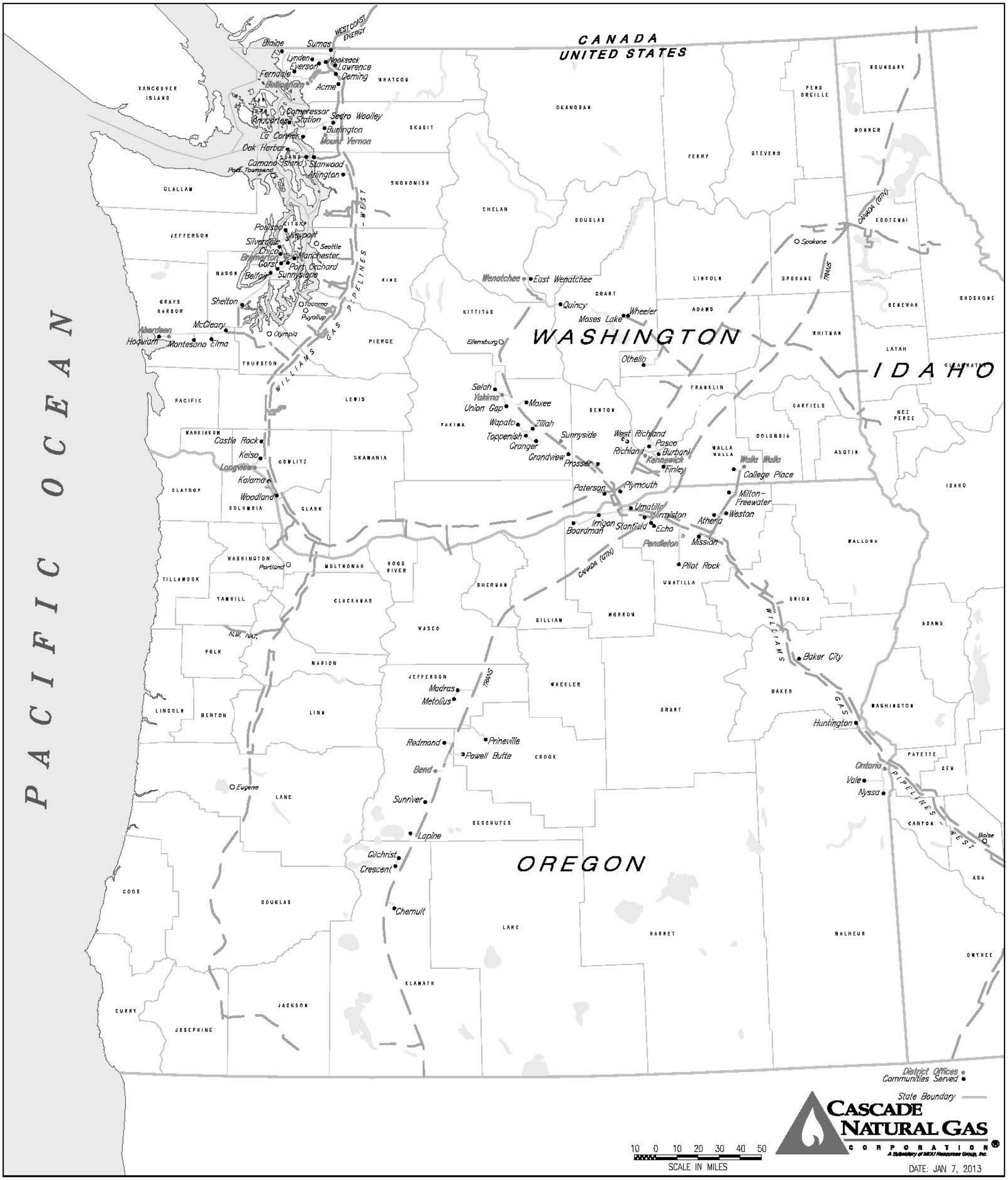
Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
01	Name of System:			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		28,123,843	
4	Gas of Others Received for Gathering (Account 489.1)	303		
5	Gas of Others Received for Transmission (Account 489.2)	305		
6	Gas of Others Received for Distribution (Account 489.3)	301		
7	Gas of Others Received for Contract Storage (Account 489.4)	307		
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328		
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)		1,262,382	
13	Gas Received from Shippers as Compressor Station Fuel			
14	Gas Received from Shippers as Lost and Unaccounted for			
15	Other Receipts (Specify) (footnote details)		97,122,330	
16	Total Receipts (Total of lines 3 thru 15)		126,508,555	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		28,851,644	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	97,122,330	
21	Deliveries of Gas Distributed for Others (Account 489.3)	301		
22	Deliveries of Contract Storage Gas (Account 489.4)	307		
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		
27	Other Gas Delivered to Storage (Explain)		375,349	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		17,096	
30	Total Deliveries (Total of lines 18 thru 29)		126,366,419	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		142,136	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		126,508,555	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) __ A Resubmission	12/31/2014	2014/Q4

System Maps

1. Furnish five copies of a system map (one with each filed copy of this report) of the facilities operated by the respondent for the production, gathering, transportation, and sale of natural gas. New maps need not be furnished if no important change has occurred in the facilities operated by the respondent since the date of the maps furnished with a previous year's annual report. If, however, maps are not furnished for this reason, reference should be made in the space below to the year's annual report with which the maps were furnished.
2. Indicate the following information on the maps:
   (a) Transmission lines.
   (b) Incremental facilities.
   (c) Location of gathering areas.
   (d) Location of zones and rate areas.
   (e) Location of storage fields.
   (f) Location of natural gas fields.
   (g) Location of compressor stations.
   (h) Normal direction of gas flow (indicated by arrows).
   (i) Size of pipe.
   (j) Location of products extraction plants, stabilization plants, purification plants, recycling areas, etc.
   (k) Principal communities receiving service through the respondent's pipeline.
3. In addition, show on each map: graphic scale of the map; date of the facts the map purports to show; a legend giving all symbols and abbreviations used; designations of facilities leased to or from another company, giving name of such other company.
4. Maps not larger than 24 inches square are desired. If necessary, however, submit larger maps to show essential information. Fold the maps to a size not larger then this report. Bind the maps to the report.

See attached map



CANADA
UNITED STATES
WASHINGTON
OREGON
IDAHO
PACIFIC OCEAN
WEST COAST ENERGY
WILLIAMS GAS PIPELINES – WEST
CANADA (GTN)
TRANS
N.W. NAT.
Blaine
Sumas
Lynden
Everson
Nooksack
Lawrence
Ferndale
Bellingham
Deming
Acme
Compressor Station
Anacortes
Sedro Woolley
Burlington
La Conner
Mount Vernon
Oak Harbor
Camano Island
Stanwood
Port Townsend
Arlington
Poulsbo
Keyport
Silverdale
Seattle
Chico
Bremerton
Manchester
Gorst
Port Orchard
Belfair
Sunnyslope
Shelton
Tacoma
Puyallup
McCleary
Aberdeen
Olympia
Hoquiam
Montesano
Elma
Wenatchee
East Wenatchee
Quincy
Moses Lake
Wheeler
Ellensburg
Othello
Spokane
Selah
Yakima
Moxee
Union Gap
Wapato
Zillah
Toppenish
Granger
Sunnyside
Grandview
Prosser
West Richland
Richland
Pasco
Burbank
Kennewick
Finley
Walla Walla
College Place
Milton-Freewater
Weston
Athena
Paterson
Plymouth
Umatilla
Hermiston
Irrigon
Boardman
Stanfield
Echo
Pendleton
Mission
Pilot Rock
Castle Rock
Kelso
Longview
Kalama
Woodland
Portland
Baker City
Huntington
Ontario
Vale
Nyssa
Boise
Madras
Metolius
Redmond
Prineville
Powell Butte
Bend
Eugene
Sunriver
Lapine
Gilchrist
Crescent
Chemult
District Offices
Communities Served
State Boundary
10 0 10 20 30 40 50
SCALE IN MILES
CASCADE NATURAL GAS CORPORATION
A Subsidiary of MDU Resources Group, Inc.
DATE: JAN 7, 2013

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2014	2014/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 4 Column: g

Regulatory accounts related to FAS158 and OR rate change adjustments

Schedule Page: 260 Line No.: 8 Column: a

The loss associated with each reacquisition consists of a reacquisition premium, other reacquisition expenses, and remaining unamortized issuance costs (Account 181) at the time of reacquisition.

(1) 7.5% Notes were reacquired in March 2007 and refunded by 5.79% Senior Notes for $40,000,000 due 3/08/2037. The remaining unamortized debt expense of $1,229,120 was reclassified to unamortized loss on reacquired debt.

Schedule Page: 261 Line No.: 5 Column: a

CIAC	2,757,224
Tax Gain (loss) on disposal of assets:	
Pre-1981 assets	(224)
Post-1980 assets	339,239
Total	**3,096,239**

Schedule Page: 261 Line No.: 10 Column: a

Tax expense	7,050,183
Depreciation provision:	
Pre-1981	(3,560)
Post-1980	22,851,843
Vacation accrual - current year	1,390,916
Bad Debt expense	1,391,878
STIP accrual - addback	980,749
SFAS No. 87 accrual - SERP/SISP expense	760,449
SFAS No. 87 pension plan accrual	358,723
Retiree Medical expense	115,537
Amort of loss on reacquired debt (4281)	40,971
Permanent Diff's:	
50% of business meals & entertainment	176,141
Lobbying (5912.4264)	122,435
Interest expense	65,258
Penalties (5984)	4,408
Total	**35,305,931**

Schedule Page: 261 Line No.: 20 Column: a

Depreciation & amortization of plant:	
Pre-1981	(220,224)
Post-1980	(37,342,012)
CC&B deduction	(1,566,582)
Repairs deduction	(3,878,645)
Deferred Gas costs	(4,940,456)
Funding of pension plan	(1,435,385)
Bad Debts written off	(1,399,974)
Vacation accrual - prior year	(1,304,023)
Customer advances - 2520.000 to 2520.2991	(1,180,780)
Bremerton MGP expenses	(840,407)
Eugene MGP expenses	(77,489)
Retiree Medical payments	(471,417)
SERP - benefit payments out of plan	(501,615)
Charitable contributions (5981.4261)	(250,153)
STIP accrual - prior year	(747,218)
263A adjustment - UNICAP	(14,949)
Permanent diff's:	
401k dividends (MDUR)	(96,807)
SERP - perm difference piece	(448,246)
Oregon State income tax	107,060
Total	**(56,609,322)**

Schedule Page: 261 Line No.: 33 Column: a

Allocated to:	409.1	409.2	Total

Washington	(4,989,631)	(379)	(4,990,010)
Oregon	(2,276,469)	(122)	(2,276,591)
Total	**((7,266,100)**	**(501)**	**(7,266,601)**

Schedule Page: 261 Line No.: 34 Column: a

Taxable Income for Federal Tax	(6,480,691)
Oregon adjustments to Federal Taxable Income:	
Oregon State Income Tax expense deducted from Federal Return	(107,060)
Bonus Depreciation adjustment	(460,882)
Post-80 gain adjustment	5,230
Taxable Income for Oregon Tax	(7,043,403)
Oregon Apportionment Factor	20.0000%
Oregon Taxable Income	(1,408,681)
Oregon Tax Rate	7.60%
Estimated Tax Return Oregon Income Tax	(107,060)
Adjustments:	
Difference between12/31/13 accrual and tax return	(301,427)
Provision for Current Oregon Income Tax	**(408,487)**

Allocated to:	409.1	409.2	Total
Total	**(406,771)**	**(1,716)**	**(408,487)**

Schedule Page: 276 Line No.: 4 Column: g

Regulatory accounts related to FAS158 and deferred tax effect of OR State tax rate increase.

Schedule Page: 276 Line No.: 4 Column: i

Regulatory accounts related to FAS158 and deferred tax effect of OR State tax rate increase.

Schedule Page: 338 Line No.: 9 Column: a

Notes to Depreciation, Depletion and Amortization of Gas Plant

Depreciation is accrued monthly on the average balance in each plant account using a rate specific to the account. The average balance is the simple average of the balance at the beginning of the month and at the end of the month. The amounts shown below represent the year-end balances of depreciable plant and the weighted average composite rates based on year-end balances in each category.

	Washington		Oregon	
Description (a)	Depreciable Plant Base (Thousands) (b)	Composite Rate (Percent) (c)	Depreciable Plant Base (Thousands) (d)	Composite Rate (Percent) (e)
Intangible plant	21,180		6,975	
Manufactured gas production	0		0	
Transmission plant	11,160	1.88%	5,863	1.92%
Distribution plant	545,674	2.62%	153,948	2.60%
General plant	39,643	3.89%	13,492	3.63%
Total -	617,657	2.87%	180,278	2.85%

Schedule Page: 354 Line No.: 75 Column: a

PTO/Incentive/Severence Liability	$692,354
Miscellaneous	1,384
Total Other Accounts	**$693,738**

INDEX

BLANK PAGE