e-FILING REPORT COVER SHEET

COMPANY NAME:

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☒ Yes, report docket number: RG 33

Report is required by: ☒ OAR 860-027-0070
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☒ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 3930 Fairview Industrial Drive SE, Salem, OR 97302.

Print

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** 2015/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).

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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 2015/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	12/31/2015

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 Tammy Nygard	12 Title Director, Accounting & Finance
13 Signature Tammy Nygard	14 Date Signed 03/25/2016

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	12/31/2015	End of 2015/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."

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
	GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
1	General Information	101		
2	Control Over Respondent	102		
3	Corporations Controlled by Respondent	103		
4	Security Holders and Voting Powers	107		
5	Important Changes During the Year	108		
6	Comparative Balance Sheet	110-113		
7	Statement of Income for the Year	114-116		
8	Statement of Accumulated Comprehensive Income and Hedging Activities	117		
9	Statement of Retained Earnings for the Year	118-119		
10	Statements of Cash Flows	120-121		
11	Notes to Financial Statements	122		
	BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)			
12	Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200-201		
13	Gas Plant in Service	204-209		
14	Gas Property and Capacity Leased from Others	212		
15	Gas Property and Capacity Leased to Others	213		
16	Gas Plant Held for Future Use	214		
17	Construction Work in Progress-Gas	216		
18	Non-Traditional Rate Treatment Afforded New Projects	217		
19	General Description of Construction Overhead Procedure	218		
20	Accumulated Provision for Depreciation of Gas Utility Plant	219		
21	Gas Stored	220		
22	Investments	222-223		
23	Investments in Subsidiary Companies	224-225		
24	Prepayments	230		
25	Extraordinary Property Losses	230		
26	Unrecovered Plant and Regulatory Study Costs	230		
27	Other Regulatory Assets	232		
28	Miscellaneous Deferred Debits	233		
29	Accumulated Deferred Income Taxes	234-235		
	BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
30	Capital Stock	250-251		
31	Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252		
32	Other Paid-in Capital	253		
33	Discount on Capital Stock	254		
34	Capital Stock Expense	254		
35	Securities issued or Assumed and Securities Refunded or Retired During the Year	255		
36	Long-Term Debt	256-257		
37	Unamortized Debt Expense, Premium, and Discount on Long-Term Debt	258-259		

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."

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
38	Unamortized Loss and Gain on Reacquired Debt	260		
39	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261		
40	Taxes Accrued, Prepaid, and Charged During Year	262-263		
41	Miscellaneous Current and Accrued Liabilities	268		
42	Other Deferred Credits	269		
43	Accumulated Deferred Income Taxes-Other Property	274-275		
44	Accumulated Deferred Income Taxes-Other	276-277		
45	Other Regulatory Liabilities	278		
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	Monthly Quantity & Revenue Data by Rate Schedule	299		
47	Gas Operating Revenues	300-301		
48	Revenues from Transportation of Gas of Others Through Gathering Facilities	302-303		
49	Revenues from Transportation of Gas of Others Through Transmission Facilities	304-305		
50	Revenues from Storage Gas of Others	306-307		
51	Other Gas Revenues	308		
52	Discounted Rate Services and Negotiated Rate Services	313		
53	Gas Operation and Maintenance Expenses	317-325		
54	Exchange and Imbalance Transactions	328		
55	Gas Used in Utility Operations	331		
56	Transmission and Compression of Gas by Others	332		
57	Other Gas Supply Expenses	334		
58	Miscellaneous General Expenses-Gas	335		
59	Depreciation, Depletion, and Amortization of Gas Plant	336-338		
60	Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340		
	COMMON SECTION			
61	Regulatory Commission Expenses	350-351		
62	Employee Pensions and Benefits (Account 926)	352		
63	Distribution of Salaries and Wages	354-355		
64	Charges for Outside Professional and Other Consultative Services	357		
65	Transactions with Associated (Affiliated) Companies	358		
	GAS PLANT STATISTICAL DATA			
66	Compressor Stations	508-509		
67	Gas Storage Projects	512-513		
68	Transmission Lines	514		
69	Transmission System Peak Deliveries	518		
70	Auxiliary Peaking Facilities	519		
71	Gas Account-Natural Gas	520		
72	Shipper Supplied Gas for the Current Quarter	521		
73	System Map	522		
74	Footnote Reference	551		
75	Footnote Text	552		
76	Stockholder's Reports (check appropriate box)			
	[ ] Four copies will be submitted [ ] No annual report to stockholders is prepared			

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	12/31/2015	End of 2015/Q4

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

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	12/31/2015	End of 2015/Q4

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 Captial, LLC	I	DE	100.00
3	Praire Cascade Energy Holdings, LLC (PCEH)	D	DE	100.00
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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	12/31/2015	End of 2015/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
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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	12/31/2015	End of 2015/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					

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 3.10% in April 2015.
9. None
10. None
11. None
12. At December 31, 2015, Corporate Officers were as follows:

President & CEO	Nicole Kivisto
Executive Vice President	Scott Madison
Vice President & Controller	Mark Chiles
Secretary	Daniel Kuntz

13. None

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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	870,184,135	801,092,163
3	Construction Work in Progress (107)	200-201	10,555,876	17,169,118
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	880,740,011	818,261,281
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		432,381,534	405,497,367
6	Net Utility Plant (Total of line 4 less 5)		448,358,477	412,763,914
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)		448,358,477	412,763,914
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	10,440,344	10,051,743
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)		10,642,374	10,253,773
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		31,796,378	25,580,052
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		2,700	2,700
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		9,489,613	14,617,476
38	Other Accounts Receivable (143)		1,964,217	643,801
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		461,439	518,925
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		118,405	5,348,433
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)		7,019,222	6,294,298
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	238,846	133,289
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	712,311	883,970
54	Prepayments (165)	230	3,572,978	5,615,309
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)		30,740,332	32,260,648
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)		85,193,563	90,861,051
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		2,218,763	2,302,962
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	51,471,119	52,727,311
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)		(57,149)	(78,383)
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	66,216,460	21,961,707
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)		867,213	908,183
78	Accumulated Deferred Income Taxes (190)	234-235	26,391,798	22,703,374
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		147,108,204	100,525,154
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		691,302,618	614,403,892

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	12/31/2015	End of 2015/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	152,703,952
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	38,204,913	42,672,119
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)		190,909,865	195,377,071
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	214,589,000	189,662,000
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)		214,589,000	189,662,000
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)		14,631,487	14,270,253
29	Accumulated Provision for Pensions and Benefits (228.3)		7,657,939	8,069,959
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)		50,960,517	606,421
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		73,274,078	22,970,768
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		0	0
39	Accounts Payable (232)		21,019,198	25,808,922
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		1,614,644	1,450,342
42	Customer Deposits (235)		1,061,068	1,773,982
43	Taxes Accrued (236)	262-263	10,490,710	8,304,409
44	Interest Accrued (237)		3,114,287	2,698,426
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)		0	6,482
49	Miscellaneous Current and Accrued Liabilities (242)	268	8,325,060	8,172,382
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)		49,784,967	52,374,945
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,075,229	2,901,261
58	Accumulated Deferred Investment Tax Credits (255)		373,122	425,699
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	21,159,604	17,328,327
61	Other Regulatory Liabilities (254)	278	3,535,105	4,133,312
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)		96,815,260	96,138,132
65	Accumulated Deferred Income Taxes - Other (283)		36,786,388	33,092,377
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		162,744,708	154,019,108
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		691,302,618	614,403,892

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	12/31/2015	End of 2015/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	283,544,904	308,032,475	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	203,122,805	223,018,531	0	0
5	Maintenance Expenses (402)	317-325	5,473,310	5,931,468	0	0
6	Depreciation Expense (403)	336-338	25,145,321	19,613,636	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	2,538,010	2,172,996	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	26,839,304	29,146,595	0	0
15	Income Taxes-Federal (409.1)	262-263	3,054,373	(7,266,100)	0	0
16	Income Taxes-Other (409.1)	262-263	57,822	(406,771)	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	41,339	14,782,814	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)		(52,577)	(57,543)	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)		266,219,707	286,935,626	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		17,325,197	21,096,849	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	12/31/2015	End of 2015/Q4

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	283,544,904	308,032,475	0	0
3						
4	0	0	203,122,805	223,018,531	0	0
5	0	0	5,473,310	5,931,468	0	0
6	0	0	25,145,321	19,613,636	0	0
7	0	0	0	0	0	0
8	0	0	2,538,010	2,172,996	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	26,839,304	29,146,595	0	0
15	0	0	3,054,373	(7,266,100)	0	0
16	0	0	57,822	(406,771)	0	0
17	0	0	41,339	14,782,814	0	0
18	0	0	0	0	0	0
19	0	0	(52,577)	(57,543)	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	266,219,707	286,935,626	0	0
26	0	0	17,325,197	21,096,849	0	0

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)		17,325,197	21,096,849	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)		9,825	22,155	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)		9,338,031	378,962	0	0
38	Allowance for Other Funds Used During Construction (419.1)		461,795	320,960	0	0
39	Miscellaneous Nonoperating Income (421)		18,357	40,686	0	0
40	Gain on Disposition of Property (421.1)		0	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		9,828,008	762,763	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	263,833	237,332	0	0
46	Life Insurance (426.2)		0	0	0	0
47	Penalties (426.3)		275,000	5,016	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		140,881	117,835	0	0
49	Other Deductions (426.5)		213,923	350	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	893,637	360,533	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	2,940	2,962	0	0
53	Income Taxes-Federal (409.2)	262-263	2,808,147	(501)	0	0
54	Income Taxes-Other (409.2)	262-263	53,161	(1,716)	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)		2,864,248	745	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		6,070,123	401,485	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		11,047,666	9,119,099	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	172,249	165,491	0	0
64	Amortization of Loss on Reacquired Debt (428.1)		40,971	40,971	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	255,279	426,797	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		301,152	289,081	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		11,215,013	9,463,277	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		12,180,307	12,035,057	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)		12,180,307	12,035,057	0	0

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	-	-	17,325,197	21,096,849	-	-
28						
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	9,825	22,155	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	9,338,031	378,962	-	-
38	-	-	461,795	320,960	-	-
39	-	-	18,357	40,686	-	-
40	-	-	-	-	-	-
41	-	-	9,828,008	762,763	-	-
42						
43			-	-		
44			-	-		
45			263,833	237,332		
46			-	-		
47			275,000	5,016		
48			140,881	117,835		
49	-	-	213,923	350	-	-
50	-	-	893,637	360,533	-	-
51						
52			2,940.00	2,962		
53	-	-	2,808,147	(501)	-	-
54	-	-	53,161	(1,716)	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-			-	-
59	-	-	2,864,248	745	-	-
60	-	-	6,070,123	401,485	-	-
61						
62	-	-	11,047,666	9,119,099	-	-
63	-	-	172,249	165,491	-	-
64	-	-	40,971	40,971	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	255,279	426,797	-	-
69	-	-	(301,152)	(289,081)	-	-
70	-	-	11,215,013	9,463,277	-	-
71	-	-	12,180,307	12,035,057	-	-
72						
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	12,180,307	12,035,057	-	-

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	12/31/2015	End of 2015/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 Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2015	Year/Period of Report End of 2015/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				12,035,057	12,035,057
5					
6					
7					
8					
9				12,180,307	12,180,307
10					

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	12/31/2015	End of 2015/Q4

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		42,672,119	47,283,729
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)		12,180,307	12,035,057
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)		16,647,513	16,646,667
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)		38,204,913	42,672,119
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		38,204,913	42,672,119
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			

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[Next page is 120]

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	12/31/2015	End of 2015/Q4

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)	12,180,307	12,035,057
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	27,683,331	21,786,632
5	Amortization of (Specify) (footnote details): Gas cost changes	14,592,366	(6,584,905)
6	Deferred Income Taxes (Net)	41,339	14,667,728
7	Investment Tax Credit Adjustments (Net)	(52,577)	57,543
8	Net (Increase) Decrease in Receivables	9,646,306	(4,943,569)
9	Net (Increase) Decrease in Inventory	66,102	2,636,216
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	(482,399)	(2,234,463)
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	(23,515,294)	(3,261,512)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	40,159,481	34,158,727
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(42,926,611)	(40,984,880)
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	461,796	320,960
27	Other (footnote details): Net increase in customer advances for construction	1,173,968	(1,394,790)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(42,214,439)	(42,700,630)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	92,427	114,642
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)		

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	12/31/2015	End of 2015/Q4

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	(20,093)	490,988
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(42,142,105)	(42,095,000)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	24,911,950	24,834,672
54	Preferred Stock		
55	Common Stock		35,000,000
56	Other (footnote details):		
57	Net Increase in Short-term Debt (c)		(11,500,000)
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	24,911,950	48,334,672
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(73,000)	(201,000)
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)	(16,640,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	8,198,950	31,493,672
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	6,216,326	23,557,399
75			
76	Cash and Cash Equivalents at Beginning of Period	25,582,752	2,025,353
77			
78	Cash and Cash Equivalents at End of Period	31,799,078	25,582,752

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) 12/31/2015	2015/Q4

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.

In 2015, Cascade Natural Gas Corporation made a prior period adjustment to correct the accounting transactions related to CIAC (Contributions in Aid of Construction). Prior to 2015 CNG had been reporting the income tax gross-up portion on CIAC's received as a reduction to property, plant and equipment (PP&E). It was determined the correct accounting was to credit FERC account 419 for this portion of the CIAC payment. The net effect of the entry was as follows: PP&E $8.7M, Accumulated Depreciation $(4.7M), Depreciation Expense $4.7M, and Interest & Dividend Income $(8.7M).

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, 2015 and 2014

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

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 615,000 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 require 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, 2015, up to the date of the issuance of these consolidated financial statements on March 30, 2016, 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 $1.1 million and $1.0 million as of December 31, 2015 and 2014, 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, 2015 and 2014 was $750,000 and $847,000, respectively.

Natural gas in storage

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 $4.1 million and $6.1 million at December 31, 2015 and 2014, 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 capitalized for the years ended December 31 was as follows:

	2015	2014
	(In thousands)	
AFUDC - borrowed	**$ 995**	$ 930
AFUDC - equity	**$ 696**	$ 1,816

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 deferred credits and other liabilities-other.

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

	2015	2014	Weighted Average Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Distribution plant	**$ 1,165,042**	$ 1,076,531	32
Transmission plant	**95,548**	89,933	41
Storage plant	**21,525**	20,161	32
General plant	**107,485**	97,475	21
Other plant	**72,743**	34,187	14
Non-depreciable plant	**7,964**	6,370	-
Construction in progress	**13,428**	47,611	-
Less: Accumulated depreciation and amortization	**533,176**	501,499	
Net property, plant and equipment	**$ 950,559**	$ 870,769	

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 2015 and 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. 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, 2015 and 2014, there were no impairment losses recorded. At December 31, 2015, 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 2015. 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 $62.8 million and $52.3 million at December 31, 2015 and 2014, 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 retirement 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. 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 which are filed annually. Natural gas costs refundable through rate adjustments were $16.7 million and $13.2 million at December 31, 2015 and 2014, respectively. Natural gas costs recoverable through rate adjustments were $8.9 million at December 31, 2014.

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-other. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in deferred credits and other

liabilities-other. 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:

	2015	2014
	(In thousands)	
Interest, net of AFUDC-borrowed of $995 and $930 in 2015 and 2014, respectively	**$ 22,625**	$ 20,211
Income taxes refunded, net	**$ (2,725)**	$ (4,758)

Noncash investing transactions at December 31 were as follows:

	2015	2014
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 2,411**	$ 1,536

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 was to be effective for the Company on January 1, 2017. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance one year and allowing entities to early adopt. With this decision, the guidance will be effective for the Company on January 1, 2018. 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.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance was effective for the Company on January 1, 2016, and is to be applied retrospectively. Early adoption of this guidance was permitted, however the Company has not elected to do so. The guidance will require a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but will not impact the Company's results of operations or cash flows.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance was effective for the Company on January 1, 2016, with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures, however it will not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with IFRS. This guidance will be effective for the Company on January 1, 2017, and should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position and cash flows.

Balance Sheet Classification of Deferred Taxes In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. The guidance will require all deferred tax assets and liabilities to be classified as noncurrent. These amendments will align GAAP with IFRS. This guidance will be effective for the Company on January 1, 2017, with early adoption permitted. Entities will have the option to apply the guidance prospectively, for all deferred tax assets and liabilities, or retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its financial position and disclosures, however it will not impact the Company's results of operations or cash flows.

Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance will be effective for the Company on January 1, 2018, with early adoption of certain amendments permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

Leases In February 2016, the FASB issued guidance regarding the accounting for leases. The guidance will require lessees to recognize on the balance sheet a lease asset and liability for those leases that were previously classified as operating leases. For income statement purposes, the guidance retained a dual model for lessee accounting requiring that the leases be classified as either operating or financing leases. Operating leases will result in straight-line expense and finance leases will result in front-loaded expense, similar to the current accounting for operating and capital leases, with classification criteria being largely similar to current guidance. The guidance for lessor accounting is largely similar to current guidance, but updated to align it with the new guidance for lessee accounting and the new revenue recognition guidance. In addition, the guidance requires quantitative and qualitative disclosures, including significant judgments made by management, that will provide greater insight into the extent of revenue and expense recognized, and expected to be recognized, from existing contracts. This guidance will be effective for the Company on January 1, 2019, with early adoption permitted. The guidance must be adopted using a modified retrospective approach and provides for certain practical expedients. The transition will require entities to apply the new guidance as of the beginning of the earliest comparative period presented. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

NOTE 2 – GOODWILL

The carrying amount of goodwill for the years ended December 31, 2015 and 2014 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 *	**2015**	2014
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(c)	**$ 57,235**	$ 58,488
Manufactured gas plant remediation (a)	Determined upon filing	**18,138**	17,276
Taxes recoverable from customers (a)	Over plant lives	**10,238**	9,199
Conservation activities (a)	Up to 28 months	**4,117**	2,945
Long-term debt refinancing costs (a)	Up to 22 years	**1,063**	1,176
Natural gas costs recoverable through rate adjustments	Up to 12 months	**---**	8,923
Other (a)	Up to 28 months	**63**	500
Total regulatory assets		**90,854**	98,507
Regulatory liabilities:			
Plant removal costs (b)		**112,383**	195,708
Natural gas costs refundable through rate adjustments		**16,667**	13,238
Taxes refundable to customers (b)		**9,292**	9,586
Other (b)		**5,797**	6,871
Total regulatory liabilities		**144,139**	225,403
Net regulatory position		**$ (53,285)**	$(126,896)

* *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 deferred credits and other liabilities - other 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, 2015 and 2014, approximately $80.6 million and $89.3 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 $3.1 million and $3.0 million as of December 31, 2015 and 2014, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2015 and 2014 were $75,000 and $160,000, 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.

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 are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using 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. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to these funds.

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, 2015 and 2014, 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, 2015, 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, 2015
	(In thousands)			
Assets:				
Money market funds	$ ---	$ 112	$ ---	$ 112
Insurance contract*	---	3,123	---	3,123
Total assets measured at fair value	$ ---	$ 3,235	$ ---	$ 3,235

** The insurance contract invests approximately 9 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 19 percent in common stock of large-cap companies, 63 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.*

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	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.*

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:

	2015		2014	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 493,307**	**$ 495,607**	$ 446,753	$ 497,661

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, 2015	Amount Outstanding at December 31, 2014	Letters of Credit at December 31, 2015	Expiration Date
			(Dollars in millions)			
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (a)	$ ---	$ ---	$ 2.2 (b)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (c)	$ 47.9	$ 21.0	$ ----	7/13/18

(a) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million.
(b) Outstanding letters of credit reduce 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.

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:

	2015	2014
	(In thousands)	
Senior Notes at a weighted average rate of 4.78%, due on dates ranging from August 31, 2017 to January 15, 2055	**$ 370,818**	$ 351,091
Medium-Term Notes, at a weighted average rate of 6.68%, due on dates ranging from September 1, 2020 to March 16, 2029	**50,000**	35,000
Credit agreement at a rate of 1.76%, due on July 13, 2018	**47,900**	21,000
Other notes, at a weighted average rate of 5.25%, due on February 1, 2035	**24,589**	39,662
Total long-term debt	**493,307**	446,753
Less current maturities	**5,273**	55,273
Net long-term debt	**$ 488,034**	$ 391,480

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2015, aggregate $5.3 million in 2016; $40.3 million in 2017; $53.2 million in 2018; none in 2019; $15.0 million in 2020 and $379.5 million thereafter.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The Company records obligations related to retirement costs of natural gas distribution mains and lines as asset retirement obligations.

A reconciliation of the Company's liability, which is included in deferred credits and other liabilities-other, for the years ended December 31 was as follows:

	2015	2014
	(In thousands)	
Balance at beginning of year	**$ 606**	$ 570
Accretion expense	**39**	36
Revisions in estimates	**115,565**	---
Balance at end of year	**$ 116,210**	$ 606

The 2015 revisions in estimates consist principally of updated natural gas distribution mains and lines asset retirement obligation costs.

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, 2015 and 2014 was $20,436 and $26,717, respectively.

Income tax expense for the years ended December 31 was as follows:

	2015	2014
	(In thousands)	
Current:		
Federal	**$ 7,184**	$ (15,703)
State	**(518)**	(992)
	6,666	(16,695)
Deferred:		
Income taxes –		
Federal	**143**	23,357
State	**(29)**	945
Investment tax credit - net	**239**	(635)
	353	23,667
Total income tax expense	**$ 7,019**	$ 6,972

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

	2015	2014
	(In thousands)	
Deferred tax assets:		
Contingency reserve	**$ 5,309**	$ 5,161
Accrued pension costs	**14,625**	18,688
Other	**12,231**	11,900
Total deferred tax assets	**32,165**	35,749
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**160,595**	158,285
Postretirement	**22,819**	23,384
Other	**6,924**	10,805
Total deferred tax liabilities	**190,338**	192,474
Net deferred income tax liability	**$ (158,173)**	$ (156,725)

As of December 31, 2015 and 2014, 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, 2014, to December 31, 2015, to deferred income tax expense:

	2015
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 1,448**
Other	**(1,095)**
Deferred income tax expense for the period	**$ 353**

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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,	**2015**		2014	
	Amount	%	Amount	%
		(Dollars in thousands)		
Computed tax at federal statutory rate	**$ 7,153**	**35.0**	$ 9,351	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	**44**	**0.2**	842	3.1
AFUDC equity	**591**	**2.9**	(636)	(2.4)
Amortization of deferral of investment tax credit	**239**	**1.2**	(331)	(1.2)
Resolution of tax matters and uncertain tax positions	**159**	**0.8**	(1,444)	(5.4)
Flow-through	**(1,483)**	**(7.3)**	(224)	(0.8)
Other	**316**	**1.5**	(586)	(2.2)
Total income tax expense	**$ 7,019**	**34.3**	$ 6,972	26.1

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 income tax examinations by tax authorities for years ending prior to 2011. With few exceptions, as of December 31, 2015, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2010.

At December 31, 2015 and 2014, there were no 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. Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2015 and 2014, the Company recognized approximately ($205,000) and $55,000, respectively, of interest expense (income) in income tax expense.

For the years ended December 31, 2015 and 2014, the Company recognized approximately $129,000 and $103,000, 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 $459,000 and $15,000 for the years ended December 31, 2015 and 2014, respectively. The Company had accrued liabilities of approximately $52,000 and $453,000 at December 31, 2015 and 2014, 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. Prior to 2014, the defined pension plan benefits and accruals were frozen. 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.

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Changes in benefit obligation and plan assets for the years ended December 31, 2015 and 2014 and amounts recognized in the Consolidated Balance Sheets at December 31, 2015 and 2014, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	**2015**	2014
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 97,789**	$ 81,928	**$ 22,012**	$ 18,923
Service cost	**---**	---	**230**	188
Interest cost	**3,540**	3,620	**792**	804
Plan participants' contributions	**---**	---	**423**	406
Actuarial (gain) loss	**(5,852)**	16,595	**(806)**	3,563
Benefits paid	**(4,423)**	(4,354)	**(2,124)**	(1,872)
Benefit obligation at end of year	**91,054**	97,789	**20,527**	22,012
Change in net plan assets:				
Fair value of plan assets at beginning of year	**72,973**	68,987	**21,464**	20,458
Actual gain (loss) on plan assets	**(2,518)**	5,051	**7**	1,796
Employer contribution	**10,911**	3,289	**114**	676
Plan participants' contributions	**---**	---	**423**	406
Benefits paid	**(4,423)**	(4,354)	**(2,124)**	(1,872)
Fair value of net plan assets at end of year	**76,943**	72,973	**19,884**	21,464
Funded status – under	**$ (14,111)**	$ (24,816)	**$ (643)**	$ (548)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ ---**	$ ---	**$ 999**	$ 1,201
Other liabilities (noncurrent)	**(14,111)**	(24,816)	**(1,642)**	(1,749)
Net amount recognized	**$ (14,111)**	$ (24,816)	**$ (643)**	$ (548)
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 45,849**	$ 45,452	**$ 7,041**	$ 7,253
Prior service credit	**---**	---	**(1,862)**	(2,018)
Total	**$ 45,849**	$ 45,452	**$ 5,179**	$ 5,235

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:

	2015	2014
	(In thousands)	
Projected benefit obligation	**$ 91,054**	$97,789
Accumulated benefit obligation	**$ 91,054**	$97,789
Fair value of plan assets	**$ 76,943**	$72,973

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	
	2015	2014	**2015**	2014
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 230**	$ 188
Interest cost	**3,540**	3,620	**792**	804
Expected return on assets	**(5,105)**	(4,292)	**(1,258)**	(1,189)
Amortization of prior service credit	**---**	---	**(156)**	(178)
Recognized net actuarial loss	**1,375**	1,031	**657**	332
Net periodic benefit cost (credit)	**(190)**	359	**265**	(43)
Other changes in plan assets and benefit obligations recognized in regulatory assets (liabilities):				
Net loss	**1,772**	15,836	**445**	2,956
Amortization of actuarial loss	**(1,375)**	(1,031)	**(657)**	(332)
Amortization of prior service credit	**---**	---	**156**	178
Total recognized in regulatory assets (liabilities)	**397**	14,805	**(56)**	2,802
Total recognized in net periodic benefit cost and regulatory assets	**$ 207**	$ 15,164	**$ 209**	$ 2,759

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost in 2016 is $1.2 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets into net periodic benefit cost in 2016 are $676,000 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	
	2015	2014	**2015**	2014
Discount rate	**4.03%**	3.73%	**4.04%**	3.73%
Expected return on plan assets	**6.75%**	7.00%	**5.75%**	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	
	2015	2014	**2015**	2014
Discount rate	**3.73%**	4.56%	**3.73%**	4.49%
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, 2015, 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 30 percent to 40 percent equity securities and 60 percent to 70 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:

	2015	2014
Health care trend rate assumed for next year	**8.0%**	6.5%
Health care cost trend rate – ultimate	**5.0%**	5.0%
Year in which ultimate trend rate achieved	**2021**	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, 2015:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 59	$ (50)
Effect on postretirement benefit obligation	$ 1,572	$ (1,348)

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, 2015 and 2014, 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, 2015, 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, 2015
		(In thousands)		
Assets:				
Cash equivalents	$ ---	$ 1,938	$ ---	$ 1,938
Equity securities:				
U.S. companies	3,501	---	---	3,501
International companies	539	---	---	539
Collective and mutual funds*	35,711	14,703	---	50,414
Corporate bonds	---	14,374		14,374
Municipal bonds	---	2,701	---	2,701
U.S. Government securities	1,223	1,578	---	2,801
Total assets measured at fair value	$ 40,974	$ 35,294	$ ---	$ 76,268

* *Collective and mutual funds invest approximately 19 percent in common stock of large-cap U.S. companies, 6 percent in common stock of mid-cap U.S. companies, 16 percent in corporate bonds, 29 percent in common stock of international companies, 16 percent in cash equivalents and 14 percent in other investments.*

	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.*

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, 2015 and 2014, 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, 2015, 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, 2015
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 809	$ ---	$ 809
Equity securities:				
U.S. companies	1,032	---	---	1,032
International companies	9	---	---	9
Insurance contract*	21	18,013	---	18,034
Total assets measured at fair value	$ 1,062	$ 18,822	$ ---	$ 19,884

** The insurance contract invests approximately 19 percent in common stock of large-cap U.S. companies, 22 percent in U.S. Government securities, 10 percent in mortgage-backed securities, 36 percent in corporate bonds and 13 percent in other investments.*

	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.*

The Company does not expect to contribute to its defined benefit pension plan and expects to contribute approximately $345,000 to its postretirement benefit plans in 2016.

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)	
2016	$ 4,532	$ 1,318	$ 2
2017	4,640	1,364	2
2018	4,797	1,360	2
2019	4,918	1,344	2
2020	5,040	1,275	2
2021-2025	26,880	6,351	6

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. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated upgrades. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was $1.4 million and $1.1 million in 2015 and 2014, respectively. The total projected benefit obligation for these plans was $15.2 million and $15.7 million at December 31, 2015 and 2014, respectively. The accumulated benefit obligations for these plans were $15.0 million and $15.7 million at December 31, 2015 and 2014, respectively. A weighted average discount rate of 3.8 percent and 3.5 percent at December 31, 2015 and 2014, respectively, and a rate of compensation increase of 4.0 percent at both December 31, 2015 and 2014, were used to determine benefit obligations. A discount rate of 3.5 percent and 4.3 percent for the years ended December 31, 2015 and 2014, respectively, and a rate of compensation increase of 4.0 percent for both years ended December 31, 2015 and 2014, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $1.0 million in 2016; $1.0 million in 2017; $1.1 million in 2018; $1.1 million in 2019; $1.1 million in 2020; and $4.7 million for the years 2021 through 2025.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2015 and 2014 were $24,000 and $15,000, respectively.

The Company had investments of $10.5 million and $10.1 million at December 31, 2015 and 2014, respectively, consisting of equity securities of $2.4 million and $2.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $7.2 million and $6.9 million, respectively, and other investments of $930,000 and $621,000, 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 $3.2 million in 2015 and $3.8 million in 2014.

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 2015 and 2014 is for the plan's year-end at December 31, 2014, and December 31, 2013, 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 2015	Pension Protection Act Zone Status 2014	FIP/RP Status Pending/ Implemented	Contributions **2015**	Contributions 2014	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2015	Green as of 5/31/2014	No	**$ 1,169**	$ 1,125	No	09/30/2016

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 as of December 31, 2014 and 2013.

NOTE 9 – REGULATORY MATTERS

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, as well as environmental remediation expenses. On November 2, 2015, Cascade, staff of the OPUC, the Citizens' Utility Board of Oregon and the Northwest Industrial Gas Users filed a settlement agreement that resolved all issues of the application and reflected a natural gas rate increase of approximately $600,000 annually or approximately .8 percent, to be effective February 1, 2016. The OPUC issued an order on December 28, 2015, accepting the settlement.

On December 1, 2015, Cascade filed an application with the WUTC for a natural gas rate increase. Cascade requested a total increase of approximately $10.5 million annually or approximately 4.2 percent above current rates. The requested increase includes costs associated with increased infrastructure investment and the associated operating expenses. The filing is pending before the WUTC. The natural gas rate increase is expected to be effective November 1, 2016. A hearing on this matter has been scheduled to begin August 2, 2016.

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 $14.8 million and $14.3 million for contingencies including litigation and environmental matters at December 31, 2015 and 2014, respectively, which include amounts that may have been accrued for matters discussed in Environmental matters within this note.

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 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 December 1, 2014 and December 1, 2015.

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 $12.9 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 $51,000 and $17,000 in 2015 and 2014, 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, 2015, were $295,000 in 2016, $160,000 in 2017, $119,000 in 2018, $91,000 in 2019, $92,000 in 2020, and $166,000 thereafter. Rent expense was $520,000 and $373,000 for the years ended December 31, 2015 and 2014, 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 45 years. The commitments under these contracts as of December 31, 2015, were $227.1 million in 2016, $146.9 million in 2017, $81.6 million in 2018, $64.7 million in 2019, $55.3 million in 2020, and $764.2 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, 2015 and 2014, respectively, were approximately $246.6 million and $252.0 million.

Guarantees

Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study. At December 31, 2015, the fixed maximum amount guaranteed under this letter of credit was $2.2 million, which is scheduled to expire in 2016. There were no amounts outstanding under this letter of credit at December 31, 2015.

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 $26.3 million and $27.8 million for the years ended December 31, 2015 and 2014, respectively and the amount charged for services received from the Company was $48,000 and $113,000 for the years ended December 31, 2015 and 2014, respectively.

The amounts included in the Consolidated Balance Sheets related to MDU and Montana-Dakota at December 31 were as follows:

	2015	2014
	(In thousands)	
Accounts receivable	**$ 108**	$ 7,628
Accounts payable	**2,706**	2,543
Dividend payable	**5,400**	5,300
Deferred charges and other assets - other	**5,937**	3,294
Deferred credits and other liabilities - other	**2,502**	3,092

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2015 and 2014, respectively, was $805,000 and $700,000, net of income taxes of $515,000 and $447,000, respectively. As of December 31, 2015, total remaining unrecognized compensation expense related to stock-based compensation was approximately $1.3 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

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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	12/31/2015	End of 2015/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)	841,287,581
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	28,896,554
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	870,184,135
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	10,555,876
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	880,740,011
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	432,381,534
15	Net Utility Plant (Total of lines 13 and 14)	448,358,477
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(424,310,707)
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	(8,070,827)
22	TOTAL In Service (Total of lines 18 thru 21)	(432,381,534)
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)	(432,381,534)

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		841,287,581		
4				
5				
6		28,896,554		
7				
8		870,184,135		
9				
10				
11		10,555,876		
12				
13		880,740,011		
14		432,381,534		
15		448,358,477		
16				
17				
18		(424,310,707)		
19				
20				
21		(8,070,827)		
22		(432,381,534)		
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33		(432,381,534)		

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	12/31/2015	End of 2015/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	27,791,845	5,744,236
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	28,155,736	5,744,236
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 Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2015	Year/Period of Report End of 2015/Q4

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				33,536,081
5				33,899,972
6				
7				
8				
9				
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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				
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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	12/31/2015	End of 2015/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	192,300	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant		87,147
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	17,247,199	87,147
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,488,653	
95	375 Structures and Improvements	1,458,788	
96	376 Mains	376,148,050	26,681,042
97	377 Compressor Station Equipment	2,000,731	97,036
98	378 Measuring and Regulating Station Equipment-General	23,611,073	1,615,110
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	194,709,972	11,653,424
101	381 Meters	50,083,161	2,141,267
102	382 Meter Installations	30,238,110	418,211
103	383 House Regulators	10,170,340	292,526
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	9,199,553	371,703
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	48,962	15,304,939
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	700,157,393	58,575,258
110	GENERAL PLANT		
111	389 Land and Land Rights	2,253,273	1,084,835
112	390 Structures and Improvements	18,394,828	1,584,933
113	391 Office Furniture and Equipment	6,985,469	666,528
114	392 Transportation Equipment	12,116,547	2,619,801
115	393 Stores Equipment	66,925	
116	394 Tools, Shop, and Garage Equipment	6,492,122	668,055
117	395 Laboratory Equipment	126,158	
118	396 Power Operated Equipment	3,597,881	2,353,045
119	397 Communication Equipment	5,423,710	1,512,172
120	398 Miscellaneous Equipment	74,922	2,659
121	Subtotal (Enter Total of lines 111 thru 120)	55,531,835	10,492,028
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)	55,531,835	10,492,028
125	TOTAL (Accounts 101 and 106)	801,092,163	74,898,669
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)	801,092,163	74,898,669

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	56,184		6,110,200	21,858,290
87				
88				192,300
89				
90				
91				87,147
92	56,184		6,110,200	23,388,362
93				
94				2,488,653
95	1,219			1,457,569
96	755,882		(6,110,200)	395,963,010
97				2,097,767
98	57,580			25,168,603
99				
100	285,329			206,078,067
101	860,370		(29,132)	51,334,926
102	13,736		(2,992)	30,639,593
103	104,121			10,358,745
104				
105	39,920		32,124	9,563,460
106				
107				
108	48,962			15,304,939
109	2,167,119		(6,110,200)	750,455,332
110				
111	61,199			3,276,909
112	413,019		(36,519)	19,530,223
113	272,665			7,379,332
114	431,725			14,304,623
115				66,925
116	4,358			7,155,819
117				126,158
118	2,390,706		5,013	3,565,233
119	14,735		36,519	6,957,666
120				77,581
121	3,588,407		5,013	62,440,469
122				
123				
124	3,588,407		5,013	62,440,469
125	5,811,710		5,013	870,184,135
126				
127				
128				
129	5,811,710		5,013	870,184,135

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	12/31/2015	End of 2015/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				
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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	12/31/2015	End of 2015/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				
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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	12/31/2015	End of 2015/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				
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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	12/31/2015	End of 2015/Q4

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	Southridge Gate Station	2,271,277	
2	Kitsap Phase IV Reinforcement	1,099,589	
3	Longview Bare Steel Pipe Repllacement	1,015,941	
4			
5			
6			
7			
8	Minor distribution system/general Plant projects each under		
9	$1 million	6,169,069	
10			
11			
12			
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45	**Total**	**10,555,876**	

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	12/31/2015	End of 2015/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				
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36				
	Total			0

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2015	Year/Period of Report End of 2015/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							
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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, 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 (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2015	End of 2015/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		
	(2) Short-Term Interest			s
	(3) Long-Term Debt	D 186,661,445	48.90	d 5.53
	(4) Preferred Stock	P		p
	(5) Common Equity	C 195,377,071	51.10	c 8.07
	(6) Total Capitalization	382,038,516	100.00	
	(7) Average Construction Work In Progress Balance	W 15,549,896		

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] 2.70

3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))] 4.13

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 2.66

b. Rate for Other Funds - 4.07

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	12/31/2015	End of 2015/Q4

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	(399,964,550)	(399,964,550)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(25,145,321)	(25,145,321)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(1,177,904)	(1,177,904)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(3,742,216)	(3,742,216)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(30,065,441)	(30,065,441)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	5,811,710	5,811,710		
13	Cost of Removal	1,273,388	1,273,388		
14	Salvage (Credit)	1,894,532	1,894,532		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	5,190,566	5,190,566		
16	Other Debit or Credit Items (Describe) (footnote details):	528,718	528,718		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(424,310,707)	(424,310,707)		
	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	(14,676,496)	(14,676,496)		
28	Distribution	(383,848,522)	(383,848,522)		
29	General	(25,785,689)	(25,785,689)		
30	TOTAL (Total of lines 21 thru 29)	(424,310,707)	(424,310,707)		

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	12/31/2015	End of 2015/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					133,289	883,970		1,017,259
2	Gas Delivered to Storage						24,473		24,473
3	Gas Withdrawn from						196,132		196,132
4	Other Debits and Credits					105,557			105,557
5	Balance at End of Year					238,846	712,311		951,157
6	Dth					70,712	146,551		217,263
7	Amount Per Dth					3.3777	4.8605		4.3779

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		9,991,110	368,230
6	SISP Plan Assets		60,633	20,371
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				
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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			10,359,340	368,230	
6			81,004	282	
7					
8					
9					
10					
11					
12					
13					
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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	12/31/2015	End of 2015/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				
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39				
40	**TOTAL Cost of Account 123.1 $**		**TOTAL**	

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				
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7				
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13				
14				
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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	141,934
2	Prepaid Rents	2,719,099
3	Prepaid Taxes	711,945
4	Prepaid Interest	
5	Miscellaneous Prepayments	
6	TOTAL	3,572,978

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	12/31/2015	End of 2015/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**						

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	12/31/2015	End of 2015/Q4

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	12/31/2015	End of 2015/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	(378,802)	23,675	various			(355,127)
6							
7	Asset Retirement Oblication	574,746	(574,746)				
8	(WA regulatory asset)						
9							
10	Asset Retirement Obligation	23,243	(23,243)				
11	(OR regulatory asset)						
12							
13	SFAS 109 Regulatory Asset	162,175	13,241	various			175,416
14	(OR regulatory asset)						
15							
16	FAS 158 Regulatory Asset	52,345,949	(695,119)				51,650,830
17	(Total system asset)						
18							
19							
20							
21							
22							
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39							
40	**Total**	52,727,311	(1,256,192)		0	0	51,471,119

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	2,897,804	5,359,908	4800-4813	4,761,464	3,496,248
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant	15,399,440	855,881			16,255,321
5	Remediation					
6						
7	WA Gas Management Sharing Margin	(86,244)	78,352	4800-4813	1,478	(9,370)
8	(amortization period 11/10-present)			4890		
9						
10	WA Over-refunded Temporary Revenue	(18,241)	14,541		294	(3,994)
11	Credit					
12						
13	OR Conservation Programs	(1,317,065)	6,128,501	4800-4813	4,190,898	620,538
14	(amortization period 11/10-present)			4890		
15						
16	OR Eugene Manufactured Gas Plant	1,876,963	174,120		168,560	1,882,523
17	Remediation					
18						
19	OR Intervenor Funding	47,339	81,195	4800-4813	52,386	76,148
20	(amortization period 11/10-present)			4890		
21						
22	OR Over-refunded Temporary Revenue	2,914	25		2,459	480
23	Credit					
24						
25	I/C Asset - Net Benefit Funds	1,957,622	1,639,794			3,597,416
26						
27	Post Retirement FAS 158	1,201,175	550,496		752,735	998,936
28						
29	ARO		39,302,214			39,302,214
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	**Total**	21,961,707	54,185,027		9,930,274	66,216,460

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[Next page is 234]

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	12/31/2015	End of 2015/Q4

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	22,703,374	(3,939,250)	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	22,703,374	(3,939,250)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	22,703,374	(3,939,250)	
8	Classification of TOTAL			
9	Federal Income Tax	21,739,456	(3,774,517)	
10	State Income Tax	963,918	(164,733)	
11	Local Income Tax			

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	12/31/2015	End of 2015/Q4

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	250,826			26,391,798
4			footnote				
5				250,826			26,391,798
6							
7				250,826			26,391,798
8							
9				240,232			25,273,741
10				10,594			1,118,057
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	12/31/2015	End of 2015/Q4

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				
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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						
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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	12/31/2015	End of 2015/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				
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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		
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40	**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	12/31/2015	End of 2015/Q4

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	

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	12/31/2015	End of 2015/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	09/15/1997	09/15/2027	20,000,000
4	Medium Term Notes	03/16/1999	03/16/2029	15,000,000
5	Medium Term Notes	02/01/2005	02/01/2035	24,589,000
6	Insured Quarterly Notes	09/01/2005	09/01/2020	15,000,000
7	Notes	03/08/2007	03/08/2037	40,000,000
8	Senior Notes (Series A)	08/23/2013	08/23/2025	25,000,000
9	Senior Notes (Series B)	08/23/2013	08/23/2028	25,000,000
10	Senior Notes (Series A)	11/24/2014	11/24/2044	12,500,000
11	Senior Notes (Series B)	11/24/2014	11/24/2054	12,500,000
12	Senior Notes (Series C)	01/15/2015	01/15/2045	12,500,000
13	Senior Notes (Series D)	01/15/2015	01/15/2055	12,500,000
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40	**TOTAL**			214,589,000

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	7.480	1,496,000			
4	7.100	1,064,700			
5	5.250	1,293,591			
6	5.210	781,500			
7	5.790	2,316,000			
8	4.110	1,027,500			
9	4.360	1,090,000			
10	4.090	502,729			
11	4.240	521,167			
12	4.090	468,646			
13	4.240	485,833			
14					
15					
16					
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40		11,047,666			

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	12/31/2015	End of 2015/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%	24,589,000	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	63,619	11/24/2014	11/24/2044
12	Senior Notes (Series B) 4.24%	12,500,000	62,268	11/24/2014	11/24/2054
13	Senior Notes (Series C) 4.09%	12,500,000	63,619	01/15/2015	01/15/2045
14	Senior Notes (Series D) 4.24%	12,500,000	62,268	01/15/2015	01/15/2055
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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	12/31/2015	End of 2015/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	85,318		6,714	78,604
4	71,331		5,036	66,295
5	1,305,705		65,015	1,240,690
6	90,003		16,176	73,827
7	172,285		7,770	164,515
8	133,181		12,584	120,597
9	136,746		10,067	126,679
10	145,250		41,500	103,750
11	59,349	41,604	39,809	61,144
12	59,432	40,254	39,234	60,452
13	22,181	41,604	2,287	61,498
14	22,181	40,254	1,723	60,712
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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	12/31/2015	End of 2015/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)	908,183	867,213
7						
8	See footnote					
9						
10						
11						
12						
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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)	12,180,307
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See footnote	(642,044)
6		
7		
8	TOTAL	(642,044)
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	38,744,645
11		
12		
13	TOTAL	38,744,645
14	Income Recorded on Books Not Included in Return	
15	AFUDC Equity	(461,796)
16	Interest capitalized adj. (IRS>books)	(152,992)
17	CIAC	(1,616,460)
18	TOTAL	(2,231,248)
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	(22,036,292)
21		
22		
23		
24		
25		
26	TOTAL	(22,036,292)
27	Federal Tax Net Income	26,015,368
28	Show Computation of Tax:	
29	Rate - 35.00%	
30	Estimated Tax Return Federal Income Tax	9,105,379
31	Adjustments:	
32	Difference between 12/31/14 accrual and tax return	(3,242,859)
33	Provision for Current Federal Income Tax (see footnote)	5,862,520
34	Oregon State Tax Calculation (see footnote)	110,983
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	12/31/2015	End of 2015/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		269,514
3	Federal Accrued		349,744
4	Fin 48 - current		
5	Gross Revenue		
6	Washington	478,083	
7	Oregon		
8	Dept of Energy - Oregon		24,146
9	City Franchise & Occupation		
10	Washington	1,737,702	
11	Oregon	764,452	
12	Property		
13	Washington	2,925,886	
14	Oregon		635,534
15	Payroll Taxes	111,950	
16	State Excise - Washington	2,286,336	
17			
18	Miscellaneous		
19			
20			
21			
22			
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	TOTAL	8,304,409	1,278,938

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		57,822		53,161
3		3,054,373		2,808,147
4				
5				
6		437,602		
7		175,231		
8		68,342		
9				
10		9,260,787		
11		2,633,908		
12				
13		2,392,383		2,940
14		1,310,831		
15		2,089,762		
16		8,352,607		
17				
18		117,851		
19				
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39				
	TOTAL	29,951,499		2,864,248

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	12/31/2015	End of 2015/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	110,983	(295,821)	48,193	185,483	
3	5,623,364	2,264,839	(48,193)	2,960,588	
4					
5					
6	437,602	475,829		439,856	
7	175,231	175,231			
8	68,342	78,734			34,538
9					
10	9,260,787	9,568,380		1,430,109	
11	2,633,908	2,618,073		780,287	
12					
13	2,395,323	2,703,857		2,617,352	
14	1,310,831	1,352,704			677,407
15	2,360,608	2,350,252		122,306	
16	8,788,396	9,120,003		1,954,729	
17					
18	117,851	117,851			
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39					
TOTAL	33,283,226	30,529,932		10,490,710	711,945

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				(239,156)	
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15				270,846	
16				435,789	
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39					
TOTAL				467,479	

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	1,830,288
2	Accounts Payable Accrual	1,722,126
3	Wages Payable	1,093,656
4	Accrued 401k Defined Contributions	1,070,588
5	Pipeline Imbalances	601,131
6	SERP Defined Contributions	583,032
7	Washington Low Income Assist Liability	447,780
8	Energy Trust of Oregon Liability	312,622
9	Other Misc. Current Liabilities (aggregate)	663,837
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45	**Total**	**8,325,060**

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	12/31/2015	End of 2015/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	(8,546,157)	805.1	35,924,586	46,470,269	1,999,526
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	(377,293)	805.1	7,804,267	11,850,950	3,669,390
5	(ammortization period 11/11-present)					
6						
7	SGL Deposit	144,810	134/228.4	24,135		120,675
8	Customer Unclaimed Credits	5,425	131	140,857	138,167	2,735
9	MDUR Interco NC Payable - FAS 158	1,285,725	228.3/182.	46,485	16,541	1,255,781
10	Pension Contribution	24,815,817	various	11,700,389	996,069	14,111,497
11						
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45	**Total**	17,328,327		55,640,719	59,471,996	21,159,604

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	(96,138,132)	(7,848)	
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(96,138,132)	(7,848)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(96,138,132)	(7,848)	
8	Classification of TOTAL			
9	Federal Income Tax	(92,755,666)	6,699	
10	State Income Tax	(3,382,466)	(14,547)	
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	570,272	182.3 &254	1,239,552	(96,815,260)
4							
5				570,272		1,239,552	(96,815,260)
6							
7				570,272		1,239,552	(96,815,260)
8							
9			254	530,262	254	1,130,230	(93,348,935)
10			182.3	40,010	182.3	109,322	(3,466,325)
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	12/31/2015	End of 2015/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	(33,092,377)	(3,972,741)	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(33,092,377)	(3,972,741)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	(33,092,377)	(3,972,741)	
8	Classification of TOTAL			
9	Federal Income Tax	(31,347,228)	(3,795,445)	
10	State Income Tax	(1,745,149)	(177,296)	
11	Local Income Tax			

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	283,223	see	4,493	(36,786,388)
4			footnote		footnote		
5				283,223		4,493	(36,786,388)
6							
7				283,223		4,493	(36,786,388)
8							
9				240,232		4,493	(34,906,934)
10				42,991			(1,879,454)
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	12/31/2015	End of 2015/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	3,345,158	282	797,485		189,729	2,737,402
2	Oregon Tax Rate Change	(52,741)	282			3,296	(49,445)
3	Regulatory Liability - Post Ret FAS 158	845,295	186			1,853	847,148
4	11/12 Under-Refunded Temporary Revenue Credit	(3,044)	186			3,044	
5	11/12 Under-Refunded Temporary Revenue Credit	(1,356)	186			1,356	
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
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42							
43							
44							
45	**Total**	4,133,312		797,485	0	199,278	3,535,105

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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	12/31/2015	End of 2015/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	155,857,090	168,894,446	155,857,090	168,894,446	13,868,795	14,911,640
2	102,005,833	113,721,758	102,005,833	113,721,758	12,847,173	13,940,004
3						
4						
5						
6						
7						
8	862,217	1,138,977	862,217	1,138,977		
9						
10						
11	24,419,536	23,895,477	24,419,536	23,895,477	100,460,563	97,122,330
12						
13						
14						
15						
16	114,760	110,952	114,760	110,952		
17						
18	285,468	270,865	285,468	270,865		
19	283,544,904	308,032,475	283,544,904	308,032,475		
20						
21	283,544,904	308,032,475	283,544,904	308,032,475		

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	12/31/2015	End of 2015/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					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)
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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	12/31/2015	End of 2015/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					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)
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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					
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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	12/31/2015	End of 2015/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)
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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	12/31/2015	End of 2015/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	285,468
13		
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39		
	Total	**285,468**

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	12/31/2015	End of 2015/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.				
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38					
39					
	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	12/31/2015	End of 2015/Q4

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

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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	144,386,647	184,357,615
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	(10,352,083)	9,992,807
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	154,738,730	174,364,808
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	4,898,359	5,944,340
87	(Less) 808.2 Gas Delivered to Storage-Credit	3,274,658	4,208,220
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	57,224	71,831
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	57,224	71,831
95	813 Other Gas Supply Expenses	445,955	412,374
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	156,751,162	176,441,471
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	156,751,162	176,441,471
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

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

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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

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	12/31/2015	End of 2015/Q4

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	1,817,712	1,693,423
205	871 Distribution Load Dispatching	609,642	748,375
206	872 Compressor Station Labor and Expenses	90,025	84,951
207	873 Compressor Station Fuel and Power	0	0

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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	4,461,823	4,096,066
209	875 Measuring and Regulating Station Expenses-General	769,463	933,813
210	876 Measuring and Regulating Station Expenses-Industrial	123,243	105,182
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,893,006	1,815,786
213	879 Customer Installations Expenses	1,456,585	1,412,842
214	880 Other Expenses	4,882,518	4,932,815
215	881 Rents	123,515	83,683
216	TOTAL Operation (Total of lines 204 thru 215)	16,227,532	15,906,936
217	Maintenance		
218	885 Maintenance Supervision and Engineering	274,022	288,325
219	886 Maintenance of Structures and Improvements	11,329	97,549
220	887 Maintenance of Mains	1,503,525	1,610,619
221	888 Maintenance of Compressor Station Equipment	26,009	17,713
222	889 Maintenance of Measuring and Regulating Station Equipment-General	328,764	361,741
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	91,173	58,992
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	1,562,654	1,794,453
226	893 Maintenance of Meters and House Regulators	1,376,621	1,376,570
227	894 Maintenance of Other Equipment	246,145	290,079
228	TOTAL Maintenance (Total of lines 218 thru 227)	5,420,242	5,896,041
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	21,647,774	21,802,977
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	5,770	26
233	902 Meter Reading Expenses	714,363	694,539
234	903 Customer Records and Collection Expenses	5,837,210	4,578,224

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	12/31/2015	End of 2015/Q4

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	812,273	1,391,878
236	905 Miscellaneous Customer Accounts Expenses	1,561	5,647
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	7,371,177	6,670,314
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	1,695,038	1,276,116
242	909 Informational and Instructional Expenses	42,579	32,163
243	910 Miscellaneous Customer Service and Informational Expenses	0	269
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	1,737,617	1,308,548
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	14,938	9,917
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	14,938	9,917
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	6,636,013	6,944,474
255	921 Office Supplies and Expenses	3,548,681	5,568,194
256	(Less) 922 Administrative Expenses Transferred-Credit	498,601	550,892
257	923 Outside Services Employed	1,613,208	1,165,240
258	924 Property Insurance	81,931	68,879
259	925 Injuries and Damages	1,306,947	1,361,498
260	926 Employee Pensions and Benefits	6,293,369	6,236,886
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	4,210	0
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	39,528	55,670
265	930.2Miscellaneous General Expenses	756,261	554,335
266	931 Rents	1,238,832	1,277,061
267	TOTAL Operation (Total of lines 254 thru 266)	21,020,379	22,681,345
268	Maintenance		
269	932 Maintenance of General Plant	53,068	35,427
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	21,073,447	22,716,772
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	208,596,115	228,949,999

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	12/31/2015	End of 2015/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					
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11					
12					
13					
14					
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17					
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19					
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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	12/31/2015	End of 2015/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	14,233	57,224		
8						
9						
10						
11						
12						
13						
14						
15						
16						
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19						
20						
21						
22						
23						
24						
25	**Total**		14,233	57,224		

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				
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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	12/31/2015	End of 2015/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	521,718
2	Software Maintenance	13,868
3	Lodging	8,161
4	Commercial Air Service	6,960
5	Meals & Entertainment	2,735
6	Office Supplies	1,534
7	Vehicle Mileage	1,022
8	Cell Phone	553
9	Training materials	126
10		
11		
12		
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23		
24		
25	**Total**	556,677

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.	256,451
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)	346,626
7	Director's Fees (paid to MDU for CNGC's share of director's expenses)	152,973
8	Miscellaneous under $250,000 (2 items)	211
9		
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24		
25	**Total**	756,261

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	12/31/2015	End of 2015/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				2,538,010
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				
9	Distribution plant	363,008			
10	General plant	23,648,155			
11	Common plant-gas	1,134,158			
12	TOTAL	25,145,321			2,538,010

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			2,538,010	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				Transmission plant
9			363,008	Distribution plant
10			23,648,155	General plant
11			1,134,158	Common plant-gas
12			27,683,331	TOTAL

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 Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2015	Year/Period of Report End of 2015/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)	263,833
5	Life Insurance (Account 426.2)	
6	Penalties (Account 426.3)	
7	WA Utilities & Trade Commission	
8	(Violation of RCW 80.28.080-Calculation of Late Payment Charges)	275,000
9	Expenditures for Certain Civic, Political and Related Activities	
10	(Account 426.4)	140,882
11	Other Duductions (Account 426.5)	213,923
12	Total Miscellaneous Income Deductions (Account 426)	893,638
13		
14	(c) Interest on Debt to Associated Companies (Account 430)	
15		
16	(d) Other Interest Expense (Account 431)	
17	Description Interest Rate	
18	Customer Depositis Various	2,136
19	Deferral Accounts-WA FERC Interest Rate	24,630
20	Deferral Accounts-OR ***	137,308
21	Interest on Short-Term Debt Various	63,368
22	Other Various	27,837
23	Total Other Interest Expense (Account 431)	255,279
24		
25	***Accounts not amortizing-8.709% (Overall rate of return granted in the last	
26	Oregon general rate filing); Accounts amortizing-1.77%	
27		
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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	12/31/2015	End of 2015/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	Oregon Public Utility Commission, General Rate Case Filing -UG-287		4,210	4,210	
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3					
4					
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25	**Total**		4,210	4,210	

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	12/31/2015	End of 2015/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	47OR	928	4,210				
2							
3							
4							
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9							
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23							
24							
25			4,210				

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	12/31/2015	End of 2015/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	(106,561)
2	Pensions – other	2,265,401
3	Post-retirement benefits other than pensions (PBOP)	232,242
4	Post- employment benefit plans	672,604
5	Other (Specify)	
6	Medical/Dental	2,984,062
7	Various	245,621
8		
9		
10		
11		
12		
13		
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39		
	Total	**6,293,369**

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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	11,068,178			11,068,178
34	Customer Accounts	3,828,018			3,828,018
35	Customer Service and Informational	3,105			3,105
36	Sales				
37	Administrative and General	5,572,224			5,572,224
38	TOTAL Operation (Total of lines 28 thru 37)	20,471,525			20,471,525
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	3,519,124			3,519,124

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)	3,519,124			3,519,124
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)	14,587,302			14,587,302
56	Customer Accounts (Total of line 34)	3,828,018			3,828,018
57	Customer Service and Informational (Total of line 35)	3,105			3,105
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	5,572,224			5,572,224
60	Total Operation and Maintenance (Total of lines 50 thru 59)	23,990,649			23,990,649
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	23,990,649			23,990,649
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	6,546,231			6,546,231
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	6,546,231			6,546,231
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	367,008			367,008
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	367,008			367,008
75	Other Accounts (Specify) (footnote details)				
76	TOTAL Other Accounts				
77	TOTAL SALARIES AND WAGES	30,903,888			30,903,888

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.	5,323,249
2	Snelson Companies, Inc.	4,114,173
3	Brothers Pipeline Corporation	2,284,357
4	Infrasource Services, LLC	2,201,267
5	Michels Corporation	2,133,043
6	Q3 Contracting	1,507,336
7	Prosource Tech, Inc.	987,796
8	Coffman Engineers	803,859
9	MRE Consulting, LTD	802,005
10	Sungard Energy Systems	567,194
11	Mesa Products, Inc.	443,651
12	Black & Veatch	361,024
13	Surveys & Analysis, Inc.	326,032
14	Deloitte & Touche	285,708
15	Snyder Gas Consulting, LLC	276,792
16	DAS-CO of Idaho	264,609
17	Parametriz, Inc.	255,318
18	Other	7,095,326
19		
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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	12/31/2015	End of 2015/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		IGCMDU.MDU RESOURCES	107	3,502,198
3		IGCMDU.MDU RESOURCES	426.1	6,586
4		IGCMDU.MDU RESOURCES	426.4	14,490
5		IGCMDU.MDU RESOURCES	426.5	213,883
6		IGCMDU.MDU RESOURCES	813	208,841
7		IGCMDU.MDU RESOURCES	875	111,429
8		IGCMDU.MDU RESOURCES	880	746,654
9		IGCMDU.MDU RESOURCES	902	156,601
10		IGCMDU.MDU RESOURCES	903	5,609,930
11		IGCMDU.MDU RESOURCES	909	19,805
12		IGCMDU.MDU RESOURCES	913	115
13				
14				
15				
16				
17				
18				
19				
20	Goods or Services Provided for Affiliated Company			
21		IGCMDU.MDU RESOURCES	920	3,941,952
22		IGCMDU.MDU RESOURCES	921	1,743,769
23		IGCMDU.MDU RESOURCES	922	(4,523)
24		IGCMDU.MDU RESOURCES	923	309,592
25		IGCMDU.MDU RESOURCES	925	1,223
26		IGCMDU.MDU RESOURCES	926	326,606
27		IGCMDU.MDU RESOURCES	930.1	18,805
28		IGCMDU.MDU RESOURCES	930.2	175,232
29		IGCMDU.MDU RESOURCES	931	1,214,386
30		IGCMDU.MDU RESOURCES	Various	(203,344)
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	12/31/2015	End of 2015/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				
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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	12/31/2015	End of 2015/Q4

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	5,728		130,608				1	
2								
3								
4								
5								
6								
7								
8								
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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	12/31/2015	End of 2015/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)			

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	12/31/2015	End of 2015/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			
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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	12/31/2015	End of 2015/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	12/31/2015	End of 2015/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					
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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	12/31/2015	End of 2015/Q4

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)		27,400,666	
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)		1,231,238	
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)		125,754,234	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		26,715,968	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	100,460,563	
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)		1,061,653	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		14,233	
30	Total Deliveries (Total of lines 18 thru 29)		128,252,417	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		840,050	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		129,092,467	

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	12/31/2015	2015/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


PACIFIC OCEAN
CANADA
UNITED STATES
WASHINGTON
IDAHO
OREGON
WEST COAST ENERGY
WILLIAMS GAS PIPELINES – WEST
CANADA (GTN)
TRANS
N.W. NAT.
VANCOUVER ISLAND
Blaine
Sumas
Lynden
Everson
Nooksack
Lawrence
Ferndale
Deming
Bellingham
Acme
Compressor Station
Sedro Woolley
Anacortes
Burlington
La Conner
Mount Vernon
Oak Harbor
Camano Island
Stanwood
Port Townsend
Arlington
Poulsbo
Keyport
Silverdale
Seattle
Chico
Manchester
Bremerton
Gorst
Port Orchard
Belfair
Sunnyslope
Shelton
Tacoma
Puyallup
McCleary
Olympia
Aberdeen
Hoquiam
Montesano
Elma
Wenatchee
East Wenatchee
Quincy
Moses Lake
Wheeler
Spokane
Ellensburg
Othello
Selah
Yakima
Union Gap
Moxee
Wapato
Zillah
Toppenish
Granger
Sunnyside
Grandview
Prosser
West Richland
Richland
Pasco
Burbank
Kennewick
Finley
Walla Walla
College Place
Castle Rock
Kelso
Longview
Kalama
Woodland
Paterson
Plymouth
Milton-Freewater
Umatilla
Hermiston
Weston
Irrigon
Boardman
Stanfield
Echo
Athena
Pendleton
Mission
Pilot Rock
Portland
Baker City
Madras
Metolius
Huntington
Redmond
Prineville
Powell Butte
Bend
Ontario
Vale
Nyssa
Eugene
Sunriver
Boise
Lapine
Gilchrist
Crescent
Chemult
WHATCOM
SAN JUAN
SKAGIT
ISLAND
OKANOGAN
FERRY
STEVENS
PEND OREILLE
BOUNDARY
BONNER
CLALLAM
SNOHOMISH
CHELAN
DOUGLAS
KOOTENAI
JEFFERSON
KITSAP
MASON
KING
LINCOLN
SPOKANE
GRANT
BENEWAH
SHOSHONE
GRAYS HARBOR
KITTITAS
ADAMS
WHITMAN
PIERCE
LATAH
CLEARWATER
THURSTON
LEWIS
FRANKLIN
PACIFIC
YAKIMA
BENTON
GARFIELD
NEZ PERCE
WAHKIAKUM
COLUMBIA
WALLA WALLA
ASOTIN
COWLITZ
SKAMANIA
CLATSOP
CLARK
WALLOWA
WASHINGTON
MULTNOMAH
HOOD RIVER
TILLAMOOK
SHERMAN
UMATILLA
UNION
YAMHILL
CLACKAMAS
GILLIAM
MORROW
WASCO
POLK
MARION
JEFFERSON
WHEELER
GRANT
BAKER
LINCOLN
BENTON
LINN
CROOK
PAYETTE
GEM
LANE
DESCHUTES
CANYON
ADA
COOS
DOUGLAS
LAKE
HARNEY
MALHEUR
OWYHEE
KLAMATH
CURRY
JOSEPHINE
JACKSON
District Offices
Communities Served
State Boundary
CASCADE NATURAL GAS CORPORATION
A Subsidiary of MDU Resources Group, Inc.
10 0 10 20 30 40 50
SCALE IN MILES
DATE: JAN 7, 2013

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.

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: a		
Customer Advances - 2520.000 to 2520.2991		1,375,911
Tax Gain (loss) on disposal of assets:		
Pre-1981 assets		(430,096)
Post-1980 assets		(1,587,859)
	Total	**(642,044)**

Schedule Page: 261 Line No.: 10 Column: a		
Tax expense		5,962,265
Vacation Accrual - current year		1,656,204
Retiree Medical Accrual		304,168
Amort of loss on reacquired debt (4281)		40,971
SFAS No. 87 pension plan accrual		(190,181)
SFAS No. 87 accrual-Serp/Sisp expense		747,702
Bad Debt Expense		812,273
Charitable Contributions (5981.4261)		202,948
Legal Reserve		10,000
Depreciation provision:		
Pre-1981		384,324
Post-1980		28,477,621
Permanent Diff's:		
50% of business meals & entertainment		159,625
Penalties (5984)		275,000
Lobbying (5912.4264)		140,881
Interest Expense		(239,156)
	Total	**38,744,645**

Schedule Page: 261 Line No.: 20 Column: a		
Vacation accrual-prior year		(1,509,219)
Depreciation & amortization of plant:		
Pre-1981		(109,330)
Post -1980		(21,067,859)
CC&B Deduction		(2,015,480)
Reparis Deduction		(2,700,809)
263A Adjustment-UNICAP		7,578
401K Dividends (MDUR)		(117,400)
SERP/SISP-perm difference piece		(358,991)
SERP-benefit payments out of plant		(531,824)
Retiree Medical payments		(100,075)
Incentive accrual-prior year		(692,354)
Deferred Gas Costs		8,923,449
Bad Debts written off		(869,759)
Bremerton & Eugene MGP expenses		(500,207)
Oregon State Income Tax		(394,012)
	Total	**(22,036,292)**

Schedule Page: 261 Line No.: 33 Column: a

Allocated to:	409.1	409.2	Total
Washington	1,776,729	2,126,610	3,903,339
Oregon	1,277,644	681,537	1,959,181

Total	**3,054,373**	**2,808,147**	**5,862,520**

Schedule Page: 261 Line No.: 34 Column: a

Taxable Income for Federal Tax	26,015,368
Oregon adjustmentsto Federal Taxable Income:	
Oregon State Income Tax expense deducted from Federal Return	394,012
Bonus Depreciation adjustment	(487,526)
Taxable Income for Oregon Tax	25,921,854
Oregon Apportionment Factor	20.0000%
Oregon Taxable Income	5,184,371
Oregon Tax Rate	7.60%
Estimated Tax Return Oregon Income Tax	394,012
Adjustments:	
Difference between 12/31/14 accrual and tax return	(237,761)
FIN 48 adjustment for 2007-2009 audit	(45,268)
Provision for Current Oregon Income Tax	**110,983**

Allocated to:	409.1	409.2	Total
Total	**57,822**	**53,161**	**110,983**

Schedule Page: 276 Line No.: 4 Column: g

Regulatroy accounts related to FAS158 and deferred tax effect of OR State tax rate increase

Schedule Page: 276 Line No.: 4 Column: i

Regulatroy accounts related to FAS158 and deferred tax effect of OR State tax rate increase

Schedule Page: 338 Line No.: 9 Column: a

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	25,919		7,981	
Manufactured gas production	0		0	
Transmission plant	17,214	1.44%	5,863	1.96%
Distribution plant	571,752	3.24%	162,913	3.13%
General plant	42,986	4.04%	16,050	3.56%
Total -	657,871	3.41%	192,807	3.32%

INDEX

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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)

SUPPLEMENTAL REPORT TO

OREGON PUBLIC UTILITY 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** 2015/Q4

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2015

INDEX

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, 2015**

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	GAS UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	67,650,226	70,092,488
3	Operating Expenses			
4	Operation Expenses (401)	4-9	48,717,077	51,204,095
5	Maintenance Expenses (402)	4-9	1,342,029	1,306,198
6	Depreciation Expense (403)	10	5,495,388	4,352,020
7	Amortization & Depletion of Utility Plant (404-405)	10	616,123	528,038
8	Amortization of Utility Plant Acquisition Adjustment (406)	10	-	-
9	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		-	-
10	Amortization of Conversion Expenses (407)		-	-
11	Taxes Other Than Income Taxes (408.1)	11	4,803,910	4,775,844
12	Income Taxes - Federal (409.1)	12	1,277,644	(2,276,469)
13	Income Taxes - Other (409.1)	13	57,822	(406,771)
14	Provision for Deferred Income Taxes (410.1)	14-21	33,062	5,095,462
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	-	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(12,377)	(13,085)
17	(Less) Gains from Disposition of Utility Plant (411.6)		-	-
18	Losses from Disposition of Utility Plant (411.7)		-	-
19	TOTAL Utility Operating Expenses (Enter Total of lines 4 through 18)		62,330,678	$ 64,565,332
20	Net Utility Operating Income (Enter Total of line 2 less 19)		5,319,548	5,527,156

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, 2015**

STATE OF OREGON - GAS OPERATING REVENUES (ACCOUNT 400)

Line No.	ACCOUNT (a)	OPERATING REVENUES CURRENT YEAR (b)	OPERATING REVENUES PREVIOUS YEAR (c)	MCF OF NATURAL GAS SOLD CURRENT YEAR (d)	MCF OF NATURAL GAS SOLD PREVIOUS YEAR (e)	AVG. NO. OF NAT. GAS CUSTUMERS PER MO. CURRENT YEAR (f)	AVG. NO. OF NAT. GAS CUSTUMERS PER MO. PREVIOUS YEAR (g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	$ 36,805,874	$ 37,588,341	3,531,723	3,647,693	58,875	57,415
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 22,085,378	$ 23,420,535	2,491,291	2,667,661	9,687	9,613
5	Large or Industrial	$ 4,505,782	$ 4,776,299	591,033	636,882	135	118
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 63,397,034	$ 65,785,175	6,614,047	6,952,236	68,697	67,146
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 63,397,034	$ 65,785,175	6,614,047	6,952,236	68,697	67,146
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 63,397,034	$ 65,785,175				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 185,988	$ 191,896				
17	489 Revenue from Trans. of Gas of Others	$ 3,992,733	$ 4,029,534				
18	490 Sales of Prod. Ext. from Natural Gas						
19	491 Revenue from Natural Gas Proc. by Others						
20	492 Incidental Gasoline and Oil Sales						
21	493 Rent from Gas Property	$ 9,728	$ 11,000				
22	494 Interdepartmental Rents	$ -					
23	495 Other Gas Revenues	$ 39,560	$ 74,883				
24	TOTAL Other Operating Revenues	$ 4,228,009	$ 4,307,313				
25	TOTAL Gas Operating Revenues	$ 67,625,043	$ 70,092,488				
26	(Less) 496 Provision for Rate Refunds						
27	TOTAL Gas Operating Revenues Net of Provision for Refunds						
28	Dist. Type Sales by States (*Incl. Main Line Sales to Residential and Commercial Customers)*	$ 58,891,252		6,023,014			
29	Main Line Industrial Sales *(Incl. Main Line Sales to Public Authorities)*	$ 4,505,782		591,033			
30	Sales for Resale						
31	Other Sales to Public Authority (Local Dist. Only)						
32	Interdepartmental Sales						
33	TOTAL *(Same as Line 10, Columns (b) and (d))*	$ 63,397,034		6,614,047			

NOTES:

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, 2015**

STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)

Report particulars concening sales of natural gas included in Account 484.

LINE No.	DEPARTMENT AND BASIS OF CHARGES (a)	POINT OF DELIVERY (b)	MCF (14.74 psia AT 60 F) (c)	REVENUE (d)
	NONE			

RENT FROM GAS PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 493, 494)

1. Report particulars concerning rents received, included in Accounts 493 and 494.
2. Minor rents may be entered at the total amount for each class of such rents.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 493 or 494.
4. Provide a subheading and total for each account.

LINE NO.	NAME OF LESSEE OR DEPARTMENT (Designate associated companies) (a)	DESCRIPTION OF PROPERTY (b)	AMOUNT OF REVENUE FOR YEAR: NATURAL GAS PROPERTY (c)	AMOUNT OF REVENUE FOR YEAR: MANUFACTURED GAS PROPERTY (d)
	Account 493			
	Stone Bros., Inc.	Northern portion of parking lot at the Hermiston office for a latte stand.	$ 9,728	
	Walla Walla Cnty commissoners		$ -	
	Allocation of Rent Paid by MDUR Group		$ -	
	Total Account 493		$ 9,728	

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CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2015**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Detail Page 4A)	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 (Enter 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 Meas. and Reg. Sta. 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 (Enter Total of lines 20 thru 28)	0	0
30	Total Natural Gas Production & Gathering (Total of lines 18 and 29)	0	0
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 (Enter Total of lines 33 thru 46)	0	0

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, 2015**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
1	A. Manufactured Gas Production Detail		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
	B2. Products Extraction (Con't)		
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 (Enter Total of lines 49 thru 56)	0	0
58	Total Products Extraction (Enter Total of lines 47 and 57)	0	0
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 (Enter Total of lines 61 thru 64)	0	0
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases	0	0
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
69	801 Natural Gas Field Line Purchases	0	0
70	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
71	803 Natural Gas Transmission Line Purchases	0	0
72	804 Natural Gas City Gate Purchases	33,441,077	41,900,435
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	2,646,632	(2,883,990)
76	805.2 Incremental Gas Cost Adjustments	0	0
77	Total Purchased Gas (Enter Total of lines 67 to 75)	36,087,709	39,016,445
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 (Enter Total of lines 80 thru 84)	0	0
86	808.1 Gas Withdrawn from Storage - Debit	465,913	537,100
87	(Less) 808.2 Gas Delivered to Storage - Credit	0	0
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	(Less) 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	(18,105)	(25,586)
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(18,105)	(25,586)
95	813 Other Gas Supply Expenses	108,233	100,206
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	36,643,750	39,628,165
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	36,643,750	39,628,165

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
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STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
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 (Enter Total of lines 101 thru 113)	0	0
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 (Enter 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 (Enter 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 and Improvements	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 (Enter Total of lines 136 thru 144)	0	0
146	Total Other Storage Expenses (Enter Total of lines 134 and 145)	0	0

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CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2015**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	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 (Enter 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 (Enter Total of lines 167 thru 174)	0	0
176	Total Liquefied Nat Gas Terminaling & Process Exp (Lines 165 & 175)	0	0
177	Total Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0
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 (Enter 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 Reg. Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	Total Maintenance (Enter Total of lines 193 thru 199)	0	0
201	Total Transmission Expenses (Enter Total of lines 191 and 200)	0	0

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, 2015**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CUURENT YEAR (b)	PREVIOUS YEAR (c)
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	502,211	448,041
205	871 Distribution Load Dispatching	140,032	167,474
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,073,812	923,627
209	875 Measuring and Regulating Station Expenses - General	223,345	247,474
210	876 Measuring and Regulating Station Expenses - Industrial	12,145	13,957
211	877 Measuring & Regulating Station Exp - City Gate Check Station	0	0
212	878 Meter and House Regulator Expenses	543,771	513,913
213	879 Customer Installations Expenses	451,504	444,085
214	880 Other Expenses	1,350,048	1,355,830
215	881 Rents	20,039	9,451
216	Total Operation (Enter Total of lines 204 thru 215)	4,316,907	4,123,852
217	Maintenance		
218	885 Maintenance Supervision and Engineering	109,200	103,119
219	886 Maintenance of Structures and Improvements	487	175
220	887 Maintenance of Mains	354,201	315,614
221	888 Maintenance of Compressor Station Equipment	781	161
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	33,903	70,387
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	60,495	18,789
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station		0
225	892 Maintenance of Services	331,052	386,657
226	893 Maintenance of Meters and House Regulators	375,529	322,281
227	894 Maintenance of Other Equipment	57,136	72,801
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,322,784	1,289,984
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	5,639,691	5,413,836
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	1,621.00	7
233	902 Meter Reading Expenses	196,877.00	196,195
234	903 Customer Records and Collection Expenses	1,344,568.00	1,034,180
235	904 Uncollectible Accounts	166,036.00	284,793
236	905 Miscellaneous Customer Accounts Expenses	372.00	1,372
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,709,474	1,516,547
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	603,418	242,830
242	909 Informational and Instructional Expenses	9,386	7,647
243	910 Miscellaneous Customer Service and Informational Expenses	0	0
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	612,804	250,477
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	2,313	505
250	916 Miscellaneous Sales Expenses	0	0
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	2,313	505

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, 2015**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	1,691,075	1,762,515
255	921 Office Supplies and Expenses	863,291	1,361,905
256	(Less) 922 Administrative Expenses Transferred - Cr.	(132,396)	(149,448)
257	923 Outside Services Employed	518,725	287,235
258	924 Property Insurance	19,885	16,738
259	925 Injuries and Damages	350,173	344,851
260	926 Employee Pensions and Benefits	1,609,528	1,563,029
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	4,210	0
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	9,501	12,886
265	930.2 Miscellaneous General Expenses	184,274	133,184
266	931 Rents	313,563	351,654
267	Total Operation (Enter Total lines 254 thru 266)	5,431,829	5,684,549
268	Maintenance		
269	935 Maintenance of General Plant	19,245	16,214
270	Total Administrative and General Exp (Total of lines 267 and 269)	5,451,074	5,700,763
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	50,059,106	52,510,293

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	FUNCTIONAL CLASSIFICATIONS (a)	OPERATION (b)	MAINTENANCE (c)	TOTAL (d)
272	Production			
273	Manufactured Gas	0	0	0
274	Natural Gas:			
275	Production and Gathering	0	0	0
276	Products Extraction	0	0	0
277	Exploration and Development	0	0	0
278	Total Natural Gas	0	0	0
279	Other Gas Supply Expenses	36,643,750	0	36,643,750
280	Total Production	36,643,750	0	36,643,750
281	Underground Storage	0	0	0
282	Other Storage	0	0	0
283	LNG Terminiling and Processing	0	0	0
284	Transmission Expenses	0	0	0
285	Distribution Expenses	4,316,907	1,322,784	5,639,691
286	Customer Accounts Expenses	1,709,474	0	1,709,474
287	Customer Service and Informational Expenses	612,804	0	612,804
288	Sales Expenses	2,313	0	2,313
289	Admin and General Expenses	5,431,829	19,245	5,451,074
290	Total Gas O. & M. Expenses	48,717,077	1,342,029	50,059,106

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURALGAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2015**

STATE OF OREGON - ALLOCATED DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Account 403, 404.1, 404.2, 404.3, 405)

(Except Amortization of Acquisition Adjustments)

Report the amounts of depreciation expense, depletion and amortization for the accounts indicated and classify according to the plant functional groups shown.

LINE NO.	FUNCTIONAL CLASSIFICATION (a)	DEPRECIATION EXPENSE (ACCOUNT 403) (b)	AMORTIZATION & DEPLETION OF PRODUCING NATURAL GAS LAND & LAND RIGHTS (ACCOUNT 404.1) (c)	AMORTIZATION OF UNDERGROUND STORAGE LAND & LAND RIGHTS (ACCOUNT 404.2) (d)	AMORTIZATION OF OTHER LIMITED-TERM GAS PLANT (ACCOUNT 404.3) (e)	AMORTIZATION OF OTHER GAS PLANT (ACCOUNT 405) (f)	TOTAL (g)
1	Intangible Plant			616,123			616,123
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	115,171					115,171
9	Distribution Plant	5,097,671					5,097,671
10	General Plant	282,546					282,546
11	Common Plant - Gas						-
12							
13							
14							
15							
16							
17							
18							
19	**TOTAL**	**5,495,388**	**-**	**616,123**	**-**	**-**	**6,111,511**

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, 2015**

STATE OF OREGON - ALLOCATED TAXES, OTHER THAN INCOME TAXES (Account 408.1)

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,375,934
2	Payroll Taxes	524,976
3	Oregon PUC Regulatory Fee	175,231
4	Oregon Department of Energy Fee	68,342
5	City Franchise Taxes	2,633,908
6	Miscellaneous Taxes	25,519
	TOTAL (Must agree with page 1, line 11)	**4,803,910**

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, 2015**

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.
3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	PARTICULARTS (Details) (a)			Amount (b)
1	Gas Operating Revenues			283,544,904
2	Operations and Maintenance Expenses			(236,279,446)
3	Taxes, Other than Income			(26,839,304)
4	State Income (Excise) Tax			(394,012)
5	Interest			(1,876,982)
6	Other Income			(1,169,549)
7	Federal Income Tax Depreciation			
8	Pre-1981			(109,330)
9	Post-1980			(21,067,859)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			(1,616,460)
12	Book depreciation included in O&M			28,861,946
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			(430,096)
15	Post-1980 assets			(1,587,859)
16	Vacation Accrual adjustment			146,985
17	Retiree Medical Accrual adjustment			204,093
18	Amort of loss on reacquired debt (4281)			40,971
19	SFAS No.87 pension plan accrual			(190,181)
20	SFAS No.87 accrual-SERP DO add back bk expense			215,878
21	SERP-perm difference piece			(358,991)
22	Bad Debt Adjustment			(57,486)
23	Charitable Contributions (5981.4261)			202,948
24	Permanent diff's			
25	50 % of business meals & entertainment			159,625
26	Penalties (5984)			275,000
27	Lobbying (5912.4264)			140,881
28	Tax exempt interest			(239,156)
29	Interest capitalized adj (IRS>books)			148,160
30	Customer Advances - 2520.000 to 2520.2991			1,375,911
31	CC&B Deduction			(2,015,480)
32	Repairs Deduction			(2,700,809)
33	Legal Reserve			10,000
34	263A Adjustment - UNICAP			7,578
35	401K Dividends (MDUR)			(117,400)
36	Severance accrual adjustment			-
37	STIP accrual adjustment			(692,354)
38	Deferred Gas Costs			8,923,449
39	Royalty Income (15% of royalty income receipts)			-
40	Broken Meter interest charges			-
41	Installment sale - Seattle GO			-
42	Bremerton MGP expenses			(449,898)
43	Eugene MGP expenses			(50,309)
44	Federal Tax Net Income			26,015,368
45	Show Computation of Tax:			
46	Federal Tax Rate			35%
47	Estimated Federal Tax			9,105,379
48	Adjustments to Estimated Federal Tax			
49	Difference between 12/31/14 accrual and tax return			(3,242,859)
50	Audit adjustment			-
51	Provision for Current Federal Income Tax			5,862,520
52	Allocated to:	409.1	409.2	Total
53	Washington	1,776,729	2,126,610	3,903,339
54	Oregon	1,277,644	681,537	1,959,181
55	Total	**3,054,373**	**2,808,147**	**5,862,520**

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, 2015**

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.
3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identify adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particularts (Details) (a)			Amount (b)
1	Gas Operating Revenues			283,544,904
2	Operations and Maintenance Expenses			(236,279,446)
3	Taxes, Other than Income			(26,839,304)
4	State Income (Excise) Tax			
5	Interest			(1,876,982)
6	Other Income			(1,169,549)
7	Federal Income Tax Depreciation			
8	Pre-1981			(109,330)
9	Post-1980			(21,574,034)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			(1,616,460)
12	Book depreciation included in O&M			28,861,946
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			(430,096)
15	Post-1980 assets			(1,569,209)
16	Vacation Accrual adjustment			146,985
17	Retiree Medical Accrual adjustment			204,093
18	Amort of loss on reacquired debt (4281)			40,971
19	SFAS No.87 pension plan accrual			(190,181)
20	SFAS No.87 accrual-SERP DO add back bk expense			215,878
21	SERP-perm difference piece			(358,991)
22	Bad Debt Adjustment			(57,486)
23	Charitable Contributions (5981.4261)			202,948
24	Permanent diff's			-
25	50 % of business meals & entertainment			159,625
26	Penalties (5984)			275,000
27	Lobbying (5912.4264)			140,881
28	Tax exempt interest			(239,156)
29	Interest capitalized adj (IRS>books)			148,160
30	Customer Advances - 2520.000 to 2520.2991			1,375,911
31	CC&B Deduction			(2,015,480)
32	Repairs Deduction			(2,700,809)
33	Repairs Deduction			10,000
34	263A Adjustment - UNICAP			7,578
35	401K Dividends (MDUR)			(117,400)
36	Severance accrual adjustment			-
37	STIP accrual adjustment			(692,354)
38	Deferred Gas Costs			8,923,449
39	Royalty Income (15% of royalty income receipts)			-
40	Broken Meter interest charges			-
41	Installment sale - Seattle GO			-
42	Bremerton MGP expenses deferred			(449,898)
43	Eugene MGP expenses deferred			(50,309)
44	Federal Tax Net Income			25,921,855
45	Oregon Apportionment Rate			20%
46	State Tax Net Income			5,184,371
47	Show Computation of Tax:			
48	State Tax Rate			7.6%
49				394,012
50	Adjustments to Estimated Federal Tax			
51	Difference between 12/31/14 accrual and tax return			(237,761)
52	FIN 48 adjustment			(45,268)
53	Provision for Current Federal Income Tax			110,983
54	Allocated to:	409.1	409.2	Total
55	Oregon	**57,822**	**53,161**	110,983

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, 2015**

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
   (a) Identify, by amount and classification, significant items for which deferred taxes are being provided.
   (b) Indicate insignificant amounts under OTHER.

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	Electric			
2				
3	Other			
4	TOTAL ELECTRIC			
5	Gas	22,703,374	(3,939,250)	-
6				
7	Other	-		
8	TOTAL GAS	22,703,374	(3,939,250)	-
9	Other (Specify)	-		
10	TOTAL (Account 190)	22,703,374	(3,939,250)	-
11	Classification of Totals			
12	Federal Income Tax	21,739,456	(3,774,517)	-
13	State Income Tax	963,918	(164,733)	-
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	See Below	(2,195,641)	-
18	Federal Income Tax - Oregon	See Below	(1,578,876)	-
19	State Income Tax - Oregon	963,918	(164,733)	-
20				
21				
22				

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	21,739,456	25,273,741
	-	-
Balance to be allocated	21,739,456	25,273,741
Washington allocation factor	75.70%	75.73%
Washington Allocated balance	16,456,768	19,139,804
Oregon allocation factor	24.30%	24.27%
Oregon Allocated balance	5,282,688	6,133,937

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS COPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2015

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
-	-	Regulatory accounts related to FAS 158 and OR rate change adjustments	250,826	Regulatory accounts related to FAS 158 and OR rate change adjustments	-	26,391,798	5
							6
						-	7
-	-		250,826		-	26,391,798	8
						-	9
-	-		250,826		-	26,391,798	10
							11
-	-		240,232		-	25,273,741	12
-	-		10,594		-	1,118,057	13
-	-		-		-	-	14
							15
							16
-	-		139,743		-	See Below	17
-	-		100,489		-	See Below	18
-	-		10,594		-	1,118,057	19
							20
							21
							22

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, 2015**

ACCUMULATED DEFERRED INCOME TAXES - Accelerated Amortization Property (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. In the space provided furnish explanations, including the following in colomnar order:
   - (a) State each certification number with a brief description of property.
   - (b) Total and amortizable cost of such property.
   - (c) Date amortization for tax purposes commenced.
   - (d) "Normal" depreciation rate used in computing the deferred tax.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric (*Total of lines 3 thru 7)*	-	-	-
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (*Total of lines 10 thru 14)*	-	-	-
16	Gas (Specify)			
17	TOTAL (Acct 281) *Total of 8, 15 & 16*	-	-	-
18	Classification of TOTAL			
19	Federal Income Tax	-	-	-
20	State Income Tax	-	-	-
21	Local Income Tax	-	-	-

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, 2015**

ACCUMULATED DEFERRED INCOME TAXES - Accelerated Amortization Property (Account 281) (continued)

(e) Tax rate used originally defer amount and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS		CREDITS			
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
-	-	-	-	-	-	-	8
							9
							10
							11
							12
							13
							14
-	-	-	-	-	-	-	15
						-	16
-	-	-	-	-	-	-	17
							18
-	-		-		-	-	19
-	-		-		-	-	20
-	-		-		-	-	21

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, 2015**

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. In the space provided furnish explanations, including the following in columnar order:
   (a) State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.)
   (b) Estimated lives (i.e. useful life, guideline life, guideline class life, etc.)
   (c) Classes of plant to which each method is being applied and date method was adopted.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Credited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	-		
3	Gas	(96,138,132)	(7,848)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(96,138,132)	(7,848)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 282) Lines 5 thru 8	(96,138,132)	(7,848)	-
10	Classification of Totals			
11	Federal Income Tax	(92,755,666)	6,699	-
12	State Income Tax	(3,382,466)	(14,547)	-
13	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See Below	3,897	-
Federal Income Tax - Oregon	See Below	2,802	-
State Income Tax - Oregon	(3,382,466)	(14,547)	-

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	(95,928,135)	(95,924,439)
Washington allocation factor	77.26%	76.46%
Washington Allocated balance relating to utility plant for ratemaking	(74,114,077)	(73,343,826)
Oregon allocation factor	22.74%	23.54%
Oregon Allocated balance relating to utility plant for ratemaking	(21,814,058)	(22,580,613)
Remaining balance to be allocated on Utility Plant	3,172,469	2,575,504
Oregon allocation factor	22.34%	22.42%
Oregon allocation	708,730	577,428
Plus Oregon Allocation of utility plant for ratemaking related balance	(21,814,058)	(22,580,613)
Total Oregon Allocated Balance	(21,105,328)	(22,003,185)

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, 2015**

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282) (continued)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account No. (g)	Amount (h)	Account No. (I)	Amount (j)	(k)	
							1
						-	2
-	-	182.3 & 254	570,272	182.3 & 254	1,239,552	(96,815,260)	3
						-	4
-	-		570,272		1,239,552	(96,815,260)	5
						-	6
							7
							8
-	-		570,272		1,239,552	(96,815,260)	9
							10
-	-	254	530,262	254	1,130,230	(93,348,935)	11
-	-	182.3	40,010	182.3	109,322	(3,466,325)	12
-	-		-		-	-	13
-	-		308,454		657,456	See Below	
-	-		221,808		472,774	See Below	
-	-		40,010		109,322	(3,466,325)	

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, 2015**

STATE OF OREGON - 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. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(33,092,377)	(3,972,741)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(33,092,377)	(3,972,741)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(33,092,377)	(3,972,741)	-
10	Classification of Totals			
11	Federal Income Tax	(31,347,228)	(3,795,445)	-
12	State Income Tax	(1,745,149)	(177,296)	-
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	See below	(2,207,815)	-
	Federal Income Tax - Oregon	See below	(1,587,630)	-
	State Income Tax - Oregon	(1,745,149)	(177,296)	-

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)	(298,911)
Washington allocation factor	77.26%	76.46%
Washington Allocated balance relating to Debt Refinancing	(252,759)	(228,547)
Oregon allocation factor	22.74%	23.54%
Oregon Allocated balance relating to Debt Refinancing	(74,395)	(70,364)
Remaining balance to be allocated on 3-factor	(31,020,074)	(34,608,023)
Oregon allocation factor	24.30%	24.27%
Oregon allocation	(7,537,878)	(8,399,367)
Plus Oregon Allocation of Debt refinancing related balance	(74,395)	(70,364)
Total Oregon Allocated Balance	(7,612,273)	(8,469,731)

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, 2015

STATE OF OREGON - ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (continued)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited Account 410.2	Amounts Credited Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
[redacted]							1
							2
-	-	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	283,223	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	4,493	(36,786,388)	3
						-	4
-	-		283,223		4,493	(36,786,388)	5
						-	6
							7
							8
-	-		283,223		4,493	(36,786,388)	9
[redacted]							10
-	-		240,232		4,493	(34,906,934)	11
-	-		42,991		-	(1,879,454)	12
-	-		-		-	-	13
-	-		139,743		2,614	See below	
-	-		100,489		1,879	See below	
-	-		42,991		-	(1,879,454)	

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, 2015**

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INVESTMENT TAX CREDIT (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction or adjustment to the account balance shown in column (g). Include in column (i) the average period over which the tax credit is amortized.

Line No.	Account Subdivision	Balance at Beginning of Year	Deferred For Year		Allocations to Current Year's Income		Adjustments	Balance at End of Year	Average period of Allocation to Income
			Account No	Amount	Account No	Amount			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(12,377)		ALLOCATED	23 Years
6	Total	0		0		(12,377)			
7	Other (list separately and show 3%, 4%, 7&, 10% and TOTAL)								
8									
9									
10									
11									
12									
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14									
15									
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17									
18									
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21									
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24									
25									

NOTES

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, 2015**

STATE OF OREGON - SITUS UTILITY PLANT

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	178,323,590		178,323,590			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	6,574,884		6,574,884			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	184,898,474	-	184,898,474	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	844,403		844,403			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	185,742,877	-	185,742,877	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(82,488,424)		(82,488,424)			
15	Net Utility Plant (Line 13 less 14)	103,254,453	-	103,254,453	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(82,484,053)		(82,484,053)			
19	Amort. and Depl. of producing natural gas land and land rights	-		-			
20	Amort. of underground storage land and land rights	-		-			
21	Amort. of other utility plant	(4,371)		(4,371)			
22	Total In-Service (Total of lines 18 thru 21)	(82,488,424)	-	(82,488,424)	-		-
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 & 29)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (lines 22,26, 30, 31 & 32)	(82,488,424)	-	(82,488,424)	-		-

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, 2015

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

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.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses 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 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 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 unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year. **(Continue on page 25)**

LINE NO.	ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
1	1. Intangible Plant						
2	301 Organization						
3	302 Franchises and Consents	73,667					73,667
4	303 Miscellaneous Intangible Plant	161,401	(48,027)				113,374
5	TOTAL Intangible Plant	235,068	(48,027)	-	-	-	187,041
6	2. Production Plant						
7	Natural Gas Production & 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 Structures	-					-
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 & Development Costs	-					-
26	TOTAL Production & Gathering Plant	-	-	-	-	-	-
27	Products Extraction Plant						
28	340 Land and Land Rights	-					-
29	341 Structures and Improvements	-					-
30	342 Extraction and Refining Equipmnet	-					-
31	343 Pipe Lines	-					-
32	344 Extracted Products Storage Equipment	-					-

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, 2015**

STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)

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 initally 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 distributed in column (f) 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 sub-account 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 also date of such filing.

LINE NO.	ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
	2. Production Plant (Con't) Products Extraction Plant (Con't)						
33	345 Compressor Equipment	-					-
34	346 Gas Measuring and Regulating Equipment	-					-
35	347 Other Equipment	-					-
36	TOTAL Products Extraction Plant	-	-	-	-	-	-
37	TOTAL Nat. Gas Production Plant	-	-	-	-	-	-
38	Mfd. Gas Production Plant (*Submit Suppl. Statement*)						-
39	TOTAL Production Plant	-	-	-	-	-	-
40	3. Natural Gas Storage & Processing Plant						
41	Underground Storage						
42	350.1 Land	-					-
43	350.2 Rights-of-Way	-					-
44	351 Structures and Improvements	-					-
45	352 Wells	-					-
46	352.1 Storage Leaseholds and Rights	-					-
47	352.2 Reservois	-					-
48	352.3 Non-Recoverable Natural Gas	-					-
49	353 Lines	-					-
50	354 Compressor Station Equipment	-					-
51	355 Measuring and Regulating Equipment	-					-
52	356 Purification Equipment	-					-
53	357 Other Equipment	-					-
54	TOTAL Underground Storage Plant	-	-	-	-	-	-
55	Other Storage Plant						
56	360 Land and Land Rights	-					
57	361 Structures and improvements	-					
58	362 Gas Holders	-					
59	363 Purification Equipment	-					
60	363.1 Liquefaction Equipment	-					
61	363.2 Vaporizing Equipment	-					-
62	363.3 Compressor Equipment	-					-
63	363.4 Measuring and Regulating Equipment	-					-
64	363.5 Other Equipment	-					-
65	TOTAL Other Storage Plant	-	-	-	-	-	-

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, 2015

STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		TOTAL Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	13,131					13,131
80	365.2	Rights of Way	7,693					7,693
81	366	Structures and Improvements	-					-
82	367	Mains	5,818,921					5,818,921
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	36,161					36,161
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
86.a	372	ARO - Transmission	-	24,733				24,733
87		TOTAL Transmission Plant	5,875,906	24,733	-	-	-	5,900,639
88		5. Distribution Plant						
89	374	Land and Land Rights	223,036					223,036
90	375	Structures and Improvements	365,004		(1,219)			363,785
91	376	Mains	77,559,875	4,969,402	(95,460)			82,433,817
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	7,750,704	153,823	(8,697)			7,895,830
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	43,417,188	3,401,158	(76,335)			46,742,011
96	381	Meters	12,414,295	533,131	(214,576)	70,081		12,802,931
97	382	Meter Installations	8,125,840	146,798	(230)		(29,584)	8,242,824
98	383	House Regulators	2,522,245	72,956	(25,968)	14,238		2,583,471
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	1,616,279	54,102	(29,584)		29,584	1,670,381
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,536	3,652,001	(4,536)			3,652,001
103		TOTAL Distribution Plant	153,999,002	12,983,371	(456,605)	84,319	-	166,610,087

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, 2015**

STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
104		6. General Plant						
105	389	Land and Land Rights	316,795	46,531	(61,199)	-	-	302,127
106	390	Structures and Improvements	3,884,201	1,192,656	(413,019)	-	-	4,663,838
107	391	Office Furniture and Equipment	176,623	32,563	(3,617)	-	-	205,569
108	392	Transportation Equipment	2,440,501	992,882	(29,697)	-	-	3,403,686
109	393	Stores Equipment	-					-
110	394	Tools, Shop and Garage Equipment	1,082,052	167,518	-	-	-	1,249,570
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	859,709	596,117	(415,270)	-	4,552	1,045,108
113	397	Communication Equipment	1,147,321	185,318	(11,500)	-	2,461	1,323,600
114	398	Miscellaneous Equipment	4,550	2,659	-	-	-	7,209
115		SUBTOTAL	9,911,752	3,216,244	(934,302)	-	7,013	12,200,707
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	9,911,752	3,216,244	(934,302)	-	7,013	12,200,707
118		TOTAL (Accounts 101 and 106)	170,021,728	16,176,321	(1,390,907)	84,319	7,013	184,898,474
119		Gas Plant Purchased (*See Instr. 8*)	-					-
120		(less) Gas Plant Sold (*See Instr. 8*)	-					-
121		Experimental Gas Plant Unclassified	-					-
122		TOTAL Gas Plant in Service	170,021,728	16,176,321	(1,390,907)	84,319	7,013	184,898,474

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, 2015**

STATE OF OREGON - SITUS 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 $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, 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 Acct. (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
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3				
4				
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52	T O T A L S -	0	0	0

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, 2015

STATE OF OREGON - SITUS CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (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 may be grouped.

Line No.	Description of Projects (a)	Construction Work In Progress - GAS (Account 107) (b)	Estimated Additional Cost of Project (c)
1	No projects equal to or above $500,000		
2			
3			
4			
5			
6	Minor installation of mains, service lines, measuring and regulating stations,	844,403	
7	meter sets and telemetering, and etc.		
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43	T O T A L -	844,403	0

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, 2015

STATE OF OREGON - SITUS 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 11, column (c), and that reported for gas plant in service, pages 24-27, 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 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.

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)
1	Balance Beginning of Year	(82,004,655)	(82,004,655)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(5,392,411)	(5,392,411)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(257,232)	(257,232)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(768,764)	(768,764)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(6,418,407)	(6,418,407)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	1,390,907	1,390,907		
12	Cost of Removal	265,356	265,356		
13	Salvage (credits)	(339,219)	(339,219)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	1,317,044	1,317,044		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(100,193)	(100,193)		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(410,339)	(410,339)		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(87,616,550)	(87,616,550)		
	Section B. Balances at End of Year According to Functional Classifications				
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	(3,288,552)	(3,288,552)		
25	Distribution	(80,677,547)	(80,677,547)		
26	General	(3,488,998)	(3,488,998)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	(87,786)	(87,786)		
27	TOTAL (*Enter Total of Lines 18 thru 26*)	(87,616,550)	(87,616,550)		

NOTE:
Row 15.02 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, 2015**

STATE OF OREGON - ALLOCATED

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	11,646,010		11,646,010			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	651,227		651,227			
7	Experimental Plant Unclassified	-					
8	TOTAL (*Enter Total of lines 3 thru 7*)	12,297,237	-	12,297,237	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	648,370		648,370			
12	Acquisition Adjustments	-					
13	Total Utility Plant (*Lines 8 thru 12*)	12,945,607	-	12,945,607	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(9,651,926)		(9,651,926)			
15	Net Utility Plant (Line 13 less 14)	3,293,681	-	3,293,681	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(7,697,723)		(7,697,723)			
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	-		-			
20	Amort. of Underground Storage Land and Land Rights	-		-			
21	Amort. of Other Utility Plant	(1,954,203)		(1,954,203)			
22	Total In-Service (*Lines 18 thru 21*)	(9,651,926)	-	(9,651,926)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and Depletion	-		-			
26	Total Leased to Others (*Lines 24 and 25*)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization and Depletion	-		-			
30	Total Leased to Others (*Lines 28 and 29*)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (*lines 22, 26, 30, 31, & 32*)	(9,651,926)	-	(9,651,926)	-		-

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, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

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.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in Parentheses 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 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 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 unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year. **(Continue on page 25)**

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
1		1. Intangible Plant						
2	301	Organization	36,952			(45)		36,907
3	302	Franchises and Consents	-					-
4	303	Miscellaneous Intangible Plant	6,703,254	1,061,837		(8,276)		7,756,815
5		TOTAL Intangible Plant	6,740,206	1,061,837	-	(8,321)	-	7,793,722
6		2. Production Plant						
7		Natural Gas Production & 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 lLand and Land Rights	-					-
13	326	Gas Well Structures	-					-
14	327	Field Compressor Station Structures	-					-
15	328	Field Measuring and Regulating Station Structures	-					-
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 Eeasuring and Regulating Station Equipment	-					-
22	335	Drilling and Cleaning Equipment	-					-
23	336	Purification Equipment	-					-
24	337	Other Equipment	-					-
25	338	Unsuccessful Exploration & Development Costs	-					-
26		TOTAL Production & Gathering Plant	-	-	-	-	-	-
27		Products Extraction Plant						
28	340	Land and Land Rights	-					-
29	341	Structures and Improvements	-					-
30	342	Extraction and Refining Equipmnet	-					-
31	343	Pipe Lines	-					-
32	344	Extracted Products Storage Equipment	-					-

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, 2015**

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Con't)

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 initally 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 distributed in column (f) 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 sub-account 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 also date of such filing.

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
		2. Production Plant (Con't)						
		Products Extraction Plant (Con't)						
33	345	Compressor Equipment	-					-
34	346	Gas Measuring and Regulating Equipment	-					-
35	347	Other Equipment	-					-
36		TOTAL Products Extraction Plant	-	-	-	-	-	-
37		TOTAL Nat. Gas Production Plant	-	-	-	-	-	-
38		Mfd. Gas Production Plant (*Submit Suppl. Statement*)						-
39		TOTAL Production Plant	-	-	-	-	-	-
40		3. Natural Gas Storage & Processing Plant						
41		Underground Storage Plant						
42	350.1	Land	-					-
43	350.2	Rights-of-Way	-					-
44	351	Structures and Improvements	-					-
45	352	Wells	-					-
46	352.1	Storage Leaseholds and Rights	-					-
47	352.2	Reservoirs	-					-
48	352.3	Non-Recoverable Natural Gas	-					-
49	353	Lines	-					-
50	354	Compressor Station Equipment	-					-
51	355	Measuring and Regulating Equipment	-					-
52	356	Purification Equipment	-					-
53	357	Other Equipment	-					-
54		TOTAL Underground Storage Plant	-	-	-	-	-	-
55		Other Storage Plant						
56	360	Land and Land Rights	-					-
57	361	Structures and Improvements	-					-
58	362	Gas Holders	-					-
59	363	Purification Equipment	-					-
60	363.1	Liquefaction Equipment	-					-
61	363.2	Vaporizing Equipment	-					-
62	363.3	Compressor Equipment	-					-
63	363.4	Measuring and Regulating Equipment	-					-
64	363.5	Other Equipment	-					-
65		TOTAL Other Storage Plant	-	-	-	-	-	-

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, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		Total Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	-					-
80	365.2	Rights-of-Way	-					-
81	366	Structures and Improvements	-					-
82	367	Mains	-					-
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	-					-
85	370	Communication Equipment	-					-
86	371	Other Equipment	-					-
87		TOTAL Transmission Plant	-	-	-	-	-	-
88		5. Distribution Plant						
89	374	Land and Land Rights	23,060			(28)		23,032
90	375	Structures and Improvements	97,003			(120)		96,883
91	376	Mains	-					-
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	-					-
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	-					-
96	381	Meters	-					-
97	382	Meter Installations	-					-
98	383	House Regulators	-					-
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	-					-
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	-					-
103		TOTAL Distribution Plant	120,063	-	-	(148)	-	119,915

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, 2015

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
104		6. General Plant						
105	389	Land and Land Rights	156,383	75,519	-	(193)	-	231,709.00
106	390	Structures and Improvements	1,391,226	28,927	-	(1,718)	(8,863)	1,409,572.00
107	391	Office Furniture and Equipment	1,515,028	153,046	(61,543)	(1,870)	-	1,604,661.00
108	392	Transportation Equipment	382,571	91,608	(9,841)	(472)	-	463,866.00
109	393	Stores Equipment	10,471	-	-	(13)	-	10,458.00
110	394	Tools, Shop, and Garage Equipment	399,016	40,037	-	(493)	-	438,560.00
111	395	Laboratory Equipment	23,542	-	-	(29)	-	23,513.00
112	396	Power Operated Equipment	(18,122)	-	-	22	-	(18,100.00)
113	397	Communication Equipment	195,273	9,893	-	(241)	-	204,925.00
114	398	Miscellaneous Equipment	14,454	-	-	(18)	-	14,436.00
115		SUBTOTAL	4,069,842	399,030	(71,384)	(5,025)	(8,863)	4,383,600.00
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	4,069,842	399,030	(71,384)	(5,025)	(8,863)	4,383,600
118		TOTAL (Accounts 101 and 106)	10,930,111	1,460,867	(71,384)	(13,494)	(8,863)	12,297,237
119		Gas Plant Purchased (*See Instr. 8*)	-					-
120		(less) Gas Plant Sold (*See Instr. 8*)	-					-
121		Experimental Gas Plant Unclassified	-					-
122		TOTAL Gas Plant in Service	10,930,111	1,460,867	(71,384)	(13,494)	(8,863)	12,297,237

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, 2015

STATE OF OREGON - ALLOCATED 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 $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, 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 End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
2				
3				
4				
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46	T O T A L S -	0	0	0

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, 2015

STATE OF OREGON - ALLOCATED CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (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 may be grouped.

Line No.	Description of Projects (a)	Construction Work In Progress (Acct 107) (b)	Estimated Additional Cost of Project (c)
1	No projects equal to or above $500,000		
2			
3	Other general plant work in progress expenditures	648,370	
4			
5			
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48	T O T A L -	648,370	0

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, 2015**

STATE OF OREGON - ALLOCATED 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 11, column (c), and that reported for gas plant in service, pages 32-35, 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 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.

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)
1	Balance Beginning of Year	(2,506,119)	(2,506,119)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(102,977)	(102,977)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(33,998)	(33,998)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	-	-		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(136,975)	(136,975)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	71,384	71,384		
12	Cost of Removal	-	-		
13	Salvage (credits)	(92)	(92)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	71,292	71,292		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	2,172	2,172		
15.02	Adjustment Due to Change in Allocation Rate	4,404	4,404		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(2,565,226)	(2,565,226)		

Section B. Balances at End of Year According to Functional Classifications

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)
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	-	-		
25	Distribution	(101,649)	(101,649)		
26	General	(2,465,749)	(2,465,749)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	2,172	2,172		
27	TOTAL (*Total of Lines 18 thru 26*)	(2,565,226)	(2,565,226)		

NOTE:
Row 15 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, 2015**

STATE OF OREGON - GAS STORED (ACCOUNT 117, 164.1, 164.2 AND 164.3)

1 Report below the information called for concerning inventories of gas stored.

2 The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Mcf of inputs and withdrawals and balance for each project, except under certain specified circumstances. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and reason for any deviation from the general basis provided by the Uniform System of Accounts. Separate schedules on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.

3 If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment and account charged or credited.

4 Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.

5 If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock", the inventory basis, and the accounting performed with respect to any encroachment of withdrawals upon "base stock", or restoration of previous encroachment including brief particulars of any such accounting during the year.

6 If respondent has provided accumulated provision for such stored gas which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of Commission authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, (e) a summary showing balance of accumulated provision and entires during year.

7 Pressure base of gas volumes reported in this schedule is 14.73 psia at 60" F.

Line No.	Description	NonCurrent (Acct 117) (a)	Current (Acct 164.1) (b)	LNG (Acct 164.2) (c)	LNG (Acct 164.3) (d)	Total (e)
1	Balance, beginning of year	Not allocated		Not allocated		Not allocated
2	Gas delivered to storage		$ 15,406			$ 15,406
3	(contract account)					
4	Gas withdrawn from storage					
5	(contra account)			$ 17,524		$ 17,524
6	Other debits or credits					
7	(explain)					
8						
9						
10						
11						
12	Balance, end of year	Not allocated		Not allocated		Not allocated
13	Mcf					
14	Amount per Mcf					
15	State basis of segregation of inventory between current and noncurrent portions:					
16						
17	Gas delivered to storage:					
18	Mcf					660
19	Amount per Mcf					23.34
20	Cost basis of gas delivered to storage:					
21	Specify: Own production (give production area, see					
22	uniform system of accounts); average system purchases;					
23	specific purchases (state which purchases).					
24	Does cost of gas delivered to storage include any expenses					
25	for use of respondent's transmission, storage, or other					
26	facilities? If so, give particulars and date of Commission					
27	approval of the accounting.					
28						
29	Gas withdrawn from storage:					
30	Mcf					3,611
31	Amount per Mcf					4.85
32	Cost basis of withdrawals:					
33	Specify: average cost, lifo, fifo, (Explain any change in					Fifo
34	inventory basis during year and give date of Commission					
35	approval of the change or approval of an inventory basis					
36	different from that referred to in uniform system of accounts.)					
37						
38						

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[Next page is 40]

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, 2015**

STATE OR OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804.1 and 805)

1. Report particulars of gas purchases during the year in the manner prescribed below. (Code numbers to be used in reporting for Columns (d), (e) and (f) will be supplied by the Commission.)

2. Provide subheadings and totals for prescribed accounts as follows:

800 Natural Gas Well Head Purchases
801 Natural Gas Field Line Purchases
802 Natural Gas Gasoline Plant Outlet Purchases
803 Natural Gas Transmission Line Purchases
804 Natural Gas City Gate Purchases
804.1 Liquefied Natural Gas Purchases
805 Other Gas Purchases

Purchases are to be reported in account number sequence; e.g., all purchases charged to Account 800, followed by charges to Account 801, etc. Under each account number, purchases should be reported by states in alphabetical order. Totals are to be shown for each account in Columns (k) and (l) and should agree with the books of account, or any differences reconciled.

3. Purchases may be reported by gas purchase contract totals (at the option of the respondent) where one contract includes two or more FERC producer rate schedules or small producer certificates, provided that the same price is being paid for all gas purchased under the contract. If two or more prices are in effect under the same contract, separate details for each price shall be reported. The name and FERC rate schedule or small producer certificate docket number of each seller included in the contract total shall be listed on separate sheets, clearly cross-referenced. Where two or more prices are in effect, the sellers at each price are to be listed separately.

4. Purchases of less than 100,000 Mcf per year per contract from sellers not affiliated with the reporting company may (at the option of the respondent) be grouped by account number, except when the purchases were permanently discountinued during the reporting year. When grouped purchases are reported, the number of grouped purchases is to be reported in Column (a). Only Columns (a), (k), and (m) are to be completed for grouped purchases; however, the Commission may request additional details when necessary. Grouped non-jurisdictional purchases should be shown on a separate line.

5. Column instructions are as follows:

Columns (a) and (d) - In reporting the names of sellers under FERC rate schedules, use the names as they appear on the filed rate schedules. Abbreviations may be used where necessary. The code number to be used is the Commission-assigned number.

Column (b) - Give the name of the producing field only for purchases at the wellhead or from field lines. The plant name should be given for purchases from gasoline plant outlets. If purchases under a contract are from more than one field or plant, use the name of the one contributing the largest volume. Use a footnote to list the other fields or plants involved.

Column (c) - State the net rate in cents per Mcf as of December 31 for the reported year, applicable to the volume shown in Column (k). The net rate includes all applicable deductions and downward adjustments. The rate is effective and is filed pursuant to applicable statues and regulations and (as to FERC rates schedules) permitted by the Commission to become effective.

Columns (e) and (f) - General Services Administration location code designations are to be used to designate the state and county where the gas is received. Where gas is received in more than one county, use the code designation for the county having the largest volume, and by footnote list the other counties involved.

Column (g) - List the assigned Commission rate schedule number or small producer certificate docket number. Use the designation "NJ" in Column (g) to indicate non-jurisdictional purchases.

Column (h) - In some cases, two or more lines will be required to report a purchase, as when two or more rates are being paid under the same contract, or when purchases under the same rate schedule are charged to more than one account. If for such reasons the producer rate schedule or non-jurisdictional purchase contract appears on more than one line, enter a numerical code (selected by the respondent) in Column (h) to so indicate. Once established, the same numerical suffix is to be used for all subsequent years reporting of the purchase. If the purchase was permanently discontinued during the reporting year, so indicate by an asterisk(*) in column (h). Column (h) is also to be used to enter any Commission assigned letter rate schedule suffix (e.g. R.S. No. 22A).

Column (I) - Show date of the gas purchase contract. If gas is purchased under a renegotiated contract, show the dates of the original and renegotiated contracts on the following line in brackets. If new acreage is dedicated by ratification of an existing contract, show the date of the ratification rather than the date of the original contract. If gas is being sold from a different reservoir than the original dedicated acreage pursuant to Section 2.56 (f) (2) of the Commission's Rules of Practice and Procedure, place the letter "A" after the contract date.

Column (j) - Show, for each purchase, the approximate BTU per cubic foot, determined in accordance with the definition in item No. 7 of the General Instructions for FERC Form 2.

Column (k) - State the volume of purchased gas as finally measured for purposes of determining the amount payable for the gas. Include current year receipts of make-up gas that was paid for in prior years.

Column (l) - State the dollar amount (omit cents) paid and previously paid for the volumes of gas shown in Col. (k).

Column (m) - State the average cost per MCF to the neareast hundredth of a cent. (Column (l) divided by Column (k) multiplied by 100.)

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, 2015**

STATE OR OREGON - GAS PURCHASES (Account 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

LINE NO.	NAME OF SELLER (DESIGNATE ASSOCIATED COMPANIES) (a)	Name of Producing Field or Gasoline Plant (b)	Net Rate Effective December 31 (c)
1	804 Natural Gas City Gate Purchases		
2	Core firm supply		
3			
4	Peaking Services		
5			
6	Interstate Pipeline Transportation		
7			
8	**TOTAL**		
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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, 2015**

STATE OR OREGON - GAS PURCHASES (Account 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

7 Code (d)	State Code (e)	County Code (f)	Rate Schedule No. (g)	Rate Schedule Suffix (h)	Date of Contract (I)	Approx. BTU Per Cu Ft (j)	Gas Purchased - Mcf (14.73 psia 60 °F) (k)	Cost of Gas (l)	Cost Per Mcf (cents) (m)	LINE NO.
										1
						10.62	6,692,881	$ 27,111,643	405.08	2
										3
								$ 369,953	n/a	4
										5
								$ 8,606,113	n/a	6
										7
							6,692,881	**$ 36,087,709**	n/a	8
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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, 2015**

STATE OF OREGON - GAS USED IN UTILITY OPERATIONS - CREDIT (Accounts 810, 811 and 812)

1 Report below particulars of credits during the year to Accounts 810, 811 and 812, which offset charges to operating expenses or other accounts for the cost of gas from the respondent's own supply.
2 Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas.
3 If the reported MCF for any use is an estimated quantity, state such fact.
4 If any natural gas was used by the respondent for which charge was not made to the appropriate operating expenses or other account, list separately in column (c) the MCF of gas so us omitting entries in columns (d) and (e).
5 Pressure base of measurement, to be reported in columns (c) and (f) is 14.73 psia at 60 °F.

LINE NO.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	Natural Gas: MCF OF GAS USED (14.73 PSIA AT 60 °F) (c)	Natural Gas: AMOUNT OF CREDIT (d)	Natural Gas: AMOUNT PER MCF (CENTS) (e)	Manufactured Gas: MCF OF GAS USED (14.73 PSIA AT 60 °F) (f)	Manufactured Gas: AMOUNT OF CREDIT (g)
1	810 Gas used for Compressor Station Fuel - Credit						
2	811 Gas used for Products Extraction - Credit						
3	(a) Gas shrinkage & other usage in respondent's own processing						
4	(b) Gas shrinkage, etc. for respondent's gas processed by others						
5	812 Gas used for Other Utility Operations - Credit	812	4,413	$ 18,105	0	0	0
6	(Report separately for each principal use. Group minor uses).						
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21							
22	**TOTAL**		4,413	$ 18,105			

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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, 2015**

STATE OF OREGON - 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 taking into consideration differences in pressure bases used in measuring MCF of natural gas received and delivered.
2 Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3 Enter in column (c) the MCF as reported in the schedules indicated for the respective items of receipts and deliveries.

LINE NO.	ITEM (a)	REFERENCE PAGE NO. (b)	MCF (14.73 PSIA AT 60 °F) (c)
1	**GAS RECEIVED**		Mcf
2	Natural gas produced		
3	LPG gas produced and mixed with natural gas		
4	Manufactured gas produced and mixed with natural gas		
5	Purchased gas:		
6	a. Wellhead		
7	b. Field lines		
8	c. Gasoline Plants		
9	d. Transmission line		
10	e. City gate under FERC rate schedules		6,697,294
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		6,697,294
14	Gas of others received for transportation		22,827,285
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		111,622
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		29,636,201

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, 2015**

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS (Con't)

4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sale.
5. If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages should be used for this purpose.

LINE NO.	ITEM (a)	REFERENCE PAGE NO. (b)	MCF (14.73 PSIA AT 60 °F) (c)
	GAS RECEIVED		
22	Natural gas sales		
23	a. Field sales:		
24	(i) To interstate pipeline companies for resale pursuant		
25	to FERC rate schedules		
26	(ii) Retail industrial sales		
27	(iii) Other field sales		
28	TOTAL FIELD SALES		
29	b. Transmission systems sales:		
30	(i) To interstate pipeline co for resale under FERC rate schedules		
31	(ii) To intrastate pipeline companies and gas utilities for resale		
32	under FERC rate schedules		
33	(iii) Mainline Industrial sales under FERC certification		
34	(iv) Other mainline industrial sales		
35	(v) Other transmission system sales		
36	TOTAL TRANSMISSION SYSTEM SALES		
37	c. Local distribution by respondent:		
38	(i) Retail industrial sales		591,033
39	(ii) Other distribution system sales		6,023,015
40	TOTAL DISTRIBUTION SYSTEM SALES		6,614,048
41	d. Interdepartmental sales		
42	TOTAL SALES		6,614,048
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		22,827,285
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		22,827,285
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		4,413
51	Natural gas delivered to underground storage		
52	Natural gas delivered to LNG storage		
53	Natural gas delivered to LNG processing		
54	Natural gas for franchise requirements		
55	Other deliveries (specify)		
56	TOTAL SALES & OTHER DELIVERIES UNACCOUNTED FOR		29,445,746
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		190,455
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		190,455
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		29,636,201

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, 2015**

STATE OF OREGON - Miscellaneous General Expeness (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

LINE NO.	ITEMS (a)	TOTAL (b)	AMOUNT APPLICABLE TO STATE OF OREGON (c)	AMOUNT APPLICABLE TO OTHER STATES (d)
1	Industry association dues.	256,451	63,021	193,430
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 oustanding 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)	346,626	84,126	262,500
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	152,973	37,127	115,846
7	Miscellaneous under $250,000 (6 items)	211	-	211
8				
9				
10				
	TOTAL	**756,261**	**184,274**	**571,987**

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, 2015**

STATE OF OREGON - POLITICAL ADVERTISING

1. List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation
2. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged.
3. Report whole dollars only. Provide a total for each account and a grand total.

LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	NONE		
	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, 2015**

STATE OF OREGON - POLITICAL CONTRIBUTIONS

1. List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. The purpose of all contributions or payments should be clearly explained.
3. Report whole dollars only. Provide a total for each account and a grand total.

LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	NONE		
	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, 2015**

STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

1. Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest."
2. Give reference if such expenditures have in the past been approved by the Commission.
   Describe the services received and the account or accounts charged. Report whole dollars only.

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	MDU/MDUR Allocated - approved in Order 07-418	107	3,502,198	849,983
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	6,586	1,598
3	MDU/MDUR Allocated - approved in Order 07-418	426.4	14,490	3,517
4	MDU/MDUR Allocated - approved in Order 07-418	426.5	213,883	51,909
5	MDU/MDUR Allocated - approved in Order 07-418	813	208,841	50,686
6	MDU/MDUR Allocated - approved in Order 07-418	875	111,429	27,044
7	MDU/MDUR Allocated - approved in Order 07-418	880	746,654	181,213
8	MDU/MDUR Allocated - approved in Order 07-418	902	156,601	38,007
9	MDU/MDUR Allocated - approved in Order 07-418	903	5,609,930	1,361,530
10	MDU/MDUR Allocated - approved in Order 07-418	909	19,805	4,807
11	MDU/MDUR Allocated - approved in Order 07-418	913	115	28
12	MDU/MDUR Allocated - approved in Order 07-418	920	3,941,952	956,712
13	MDU/MDUR Allocated - approved in Order 07-418	921	1,743,769	423,213
14	MDU/MDUR Allocated - approved in Order 07-418	922	(4,523)	(1,098)
15	MDU/MDUR Allocated - approved in Order 07-418	923	309,592	75,138
16	MDU/MDUR Allocated - approved in Order 07-418	925	1,223	297
17	MDU/MDUR Allocated - approved in Order 07-418	926	326,606	79,267
18	MDU/MDUR Allocated - approved in Order 07-418	930.1	18,805	4,564
19	MDU/MDUR Allocated - approved in Order 07-418	930.2	175,232	42,529
20	MDU/MDUR Allocated - approved in Order 07-418	931	1,214,386	294,731
21	Other Services	VAR	(203,344)	9,307
	TOTALS		18,114,230	4,454,982

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, 2015**

STATE OF OREGON - Donations and Memberships

1. List all donations and membership expenditures made by the utility during the year and the accounts charged. Give the name, city and state of each organization to whom a donation has been made. Group donations under headings such as:
   a. Contributions to and memberships in charitable organizations
   b. Organizations of the utility industry
   c. Technical and professional organizations
   d. Commercial and trade organizations
   e. All other organizations and kinds of donations and
2. List donations by type and group by the account charged. Report whole dollars only. Provide a total for each group of donations.

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	*(a) Contributions to and memberships in charitable organizations:*			
2	American Red Cross (WA and OR)	426.1	7,500	1,820
3	Boys & Girls Clubs (WA and OR)	426.1	5,800	1,213
4	MDU Resources Foundation (Bismark, ND)	426.1	76,668	18,608
5	United Way (WA and OR)	426.1	4,353	2,268
6	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,135
7	Other Organizations (59 organizations)	426.1/880.0	28,613	12,887
8	Total contributions to and memberships in charitable organizations		172,934	48,931
9	*(b) Organizations of the Utility Industry:*			
10	American Gas Association (Washington D.C.)	426.4/930.2	127,339	30,905
11	Northwest Gas Association (West Linn, OR)	426.1/921.0/930.2	64,692	15,701
12	Other Organizations (8 organizations)	426.1/921.0/930.2	3,829	869
13	Total contributions to Organizations of the Utility Industry		195,860	47,475
14	*(c) Technical and Professional Organizations*			
15	National Association of Corrosion Engineers (Houston, TX)	921.0/880.0	2,500	548
16	Other Organizations (8 organizations)	880.0/921.0	2,047	641
17	Total contributions to Professional Organizations		4,547	1,189
18	*(d) Commercial and Trade Organizations*			
19	Association of Washington Business (Olympia, WA)	426.4/921.0/930.2	63,000	15,290
20	Chamber of Commerce-38 (WA and OR)	426.1/880.0/930.2	35,439	9,309
21	Economic Development Councils-9 (WA and OR)	426.1/880.0	12,950	8,500
22	Other Organizations (7 organizations)	426.1/880.0/921.0/930.2	4,072	693
23	Total contributions to Commercial and Trade Organizations		115,461	33,792
24	*(e) Other Organizations & Donations*			
25	MDU Resources expenses (Bismark, ND)	426.1/921.0/930.7	34,425	8,355
26	Grandridge Business Park	930.2	6,063	1,472
27	Other Organizations (17 organizations)	426.1/921.0/930.2	1,741	966
28	Total Other Organizations		42,229	10,793
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	TOTAL		**531,031**	**142,180**

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, 2015**

STATE OF OREGON - OFFICERS' SALARIES

1. Report below the name, title and salary for the year for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principle 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 date the change in incumbency was made.
3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

LINE NO.	TITLE (a)	NAME OF OFFICER (b)	SALARY FOR YEAR TOTAL (a)	SALARY FOR YEAR OREGON (a)
1	President and CEO of MDU Utilities Group 1/	Nicole A. Kivisto	4/	
2	Chairman of the Board 2/	David L. Goodin	4/	
3	Executive VP & General Manager 3/	Scott W. Madison	4/	
4	VP Operations	Eric P. Martuscelli	4/	
5	Vice President, Controller, Asst. Treasurer and Asst. Secretary 3/	Mark A. Chiles	4/	
6	Vice President-HR, Customer Service and Safety 1/	Anne M. Jones	4/	
7	Assistant Secretary 2/	Julie A. Krenz	4/	
8	General Counsel and Secretary 2/	Paul K. Sandness	4/	
9	Assistant Secretary 2/	Daniel S. Kuntz	4/	
10	Treasurer 2/	Jason L. Vollmer	4/	
11	Executive VP -Utility Operations Support 1/	Michael J. Gardner	4/	
12				
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 included on filed reports with OPUC.			
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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, 2015

STATE OF OREGON-DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services, traffic settlements, amounts paid for general services and licenses, accruals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than *affiliates)* to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint agreement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

LINE NO.	NAME OF RECIPIENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Black & Veatch	Consulting	141,111
2	McDowell Rackner & Gibson	Legal	106,448
3	Northwest Metal Fab & Pipe, Inc	Construction	92,272
4	Surveys & Analysis, Inc	Construction	79,128
5	Deloitte & Touche, LLP	Audit	69,341
6	Eugene Water & Electric Board	Construction	47,544
7	Evergreen Financial Services	Collections	29,723
8	Express Employment Professionals	Temporary Employment	29,304
9	Hickman Williams & Associates	Legal	26,919
10	Certified Personnel Service Agency	Temporary Employment	26,479
11	Others < $25,000		585,811
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	TOTAL		**1,234,080**

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, 2015**

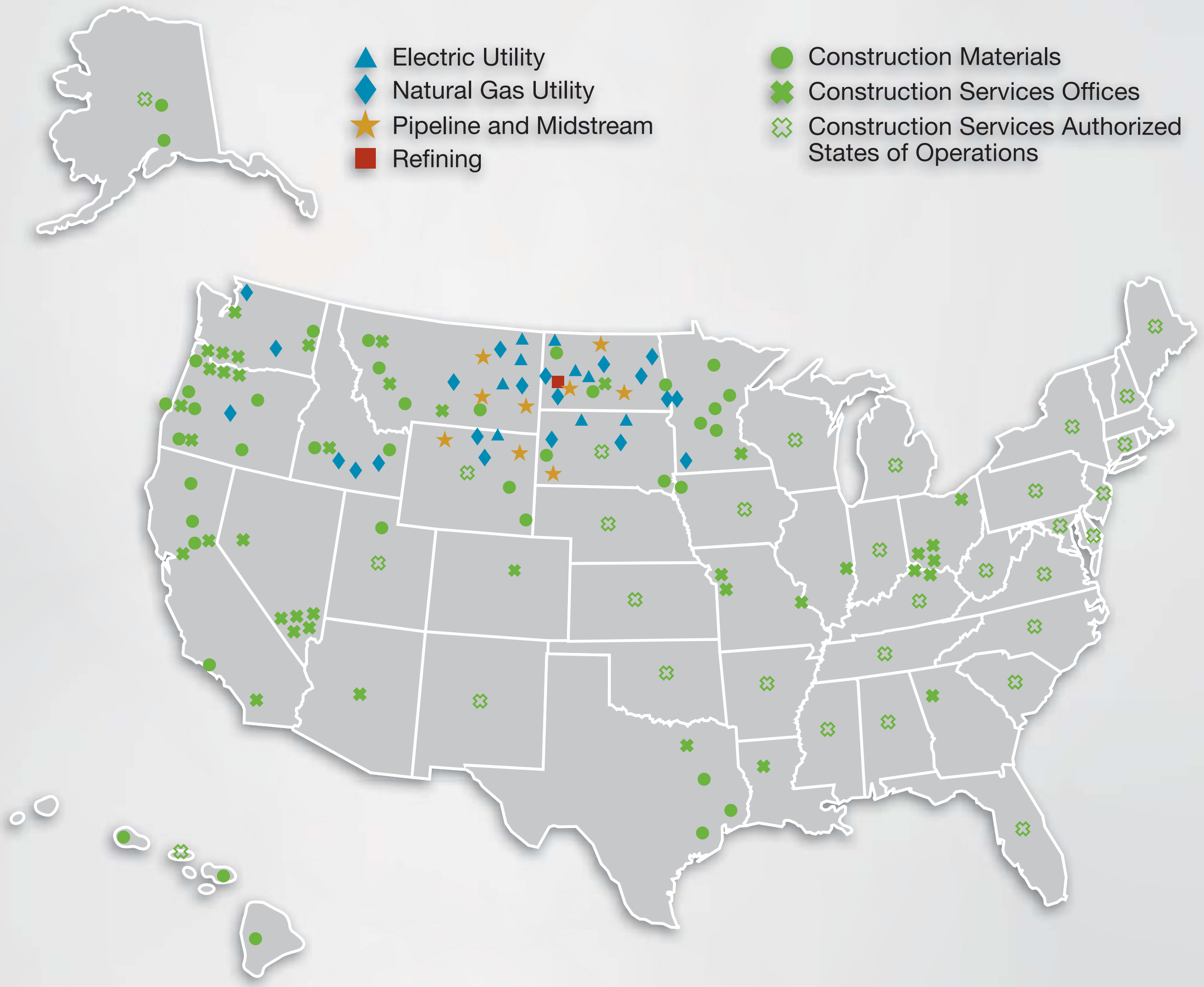
In order to help us with production of our Oregon Utility Statistics publication, please indicate.

Oregon Production Statistics (therms)	
Gas Produced	
Gas Purchased	314,639,215
Total Receipts	314,639,215
Gas Sales	312,570,352
Gas used by Company	46,851
Gas Delivered to LNG Storage - Net	
Losses & Billing Delay	2,022,012
Total Disbursements	314,639,215
Oregon Revenue by Service Class	
Residential	$ 36,805,874
Commercial & Industrial	$ 26,591,159
Firm	
Interruptible	
Transportation	$ 3,992,733
Total	$ 67,389,766
Gas Sold in Therms (Oregon)	
Residential	37,495,313
Commercial & Industrial	32,724,170
Firm	
Interruptible	
Transportation	242,350,869
Total	312,570,352
Average Number of Customers	
Residential	58,875
Commercial & Industrial	9,822
Firm	
Interruptible	
Transportation	35
Total	68,732

MDU RESOURCES
GROUP, INC.

2015 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, pipeline and midstream, construction materials and services and a diesel refinery.

Highlights

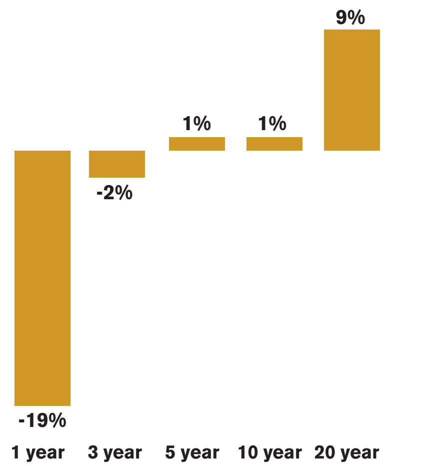
Years ended December 31,	2015	2014
	(In millions, where applicable)	
Operating revenues	**$4,191.5**	$4,114.9
Operating income	**$ 254.1**	$ 319.4
Earnings (loss) on common stock	**$ (623.1)**	$ 297.5
Adjustments net of tax:		
Exploration and production business	**787.6**	(97.3)
Other adjustments	**15.5**	5.3
Adjusted earnings	**$ 180.0**	$ 205.5
Earnings (loss) per share	**$ (3.20)**	$ 1.55
Adjusted earnings per share	**$ .92**	$ 1.07
Dividends declared per common share	**$ .7350**	$ .7150
Weighted average common shares outstanding – diluted	**195.0**	192.6
Total assets	**$ 6,628**	$ 7,832
Total equity	**$ 2,521**	$ 3,250
Total debt	**$ 1,917**	$ 2,094
Capitalization ratios:		
Total equity	**56.8%**	60.8%
Total debt	**43.2**	39.2
	100%	100%
Price/earnings from continuing operations ratio (12 months ended)	**23.8x**	24.7x
Book value per common share	**$ 12.83**	$ 16.66
Market value as a percent of book value	**142.8%**	141.1%
Employees	**8,689**	8,451

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: an exploration and production loss of $787.6 million in 2015 and earnings of $97.3 million in 2014, natural gas gathering asset impairments of $10.6 million in 2015, the company's portion of additional startup costs at Dakota Prairie Refining of $2.0 million in 2015, a multiemployer pension plan withdrawal liability of $1.5 million in 2015 and $8.4 million in 2014, an underperforming, non-strategic asset loss of $1.4 million in 2015, and earnings from discontinued operations of $3.1 million in 2014 related to other operations. 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 2015 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

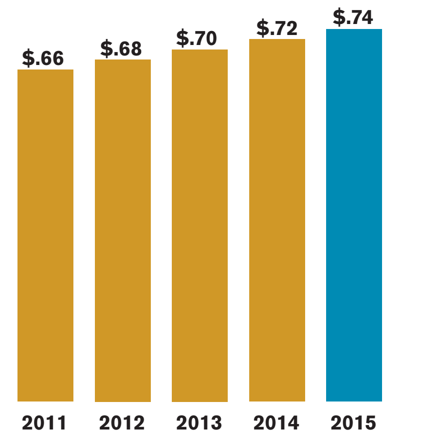
(as of December 31, 2015)



Dividends

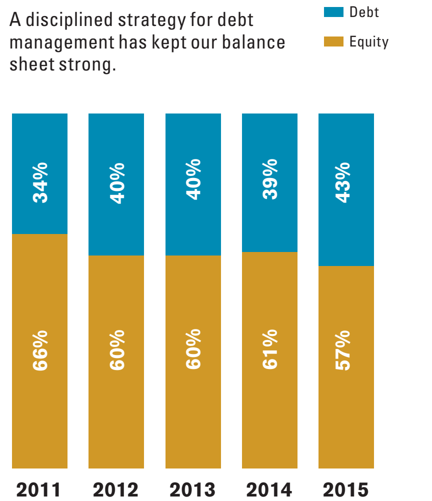
(per common share)

We have paid dividends uninterrupted for 78 years.



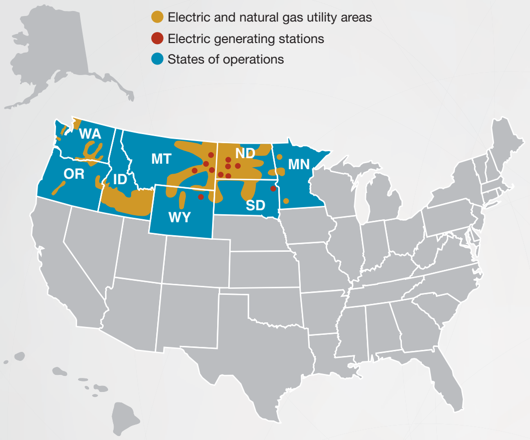
Capitalization Ratios

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.



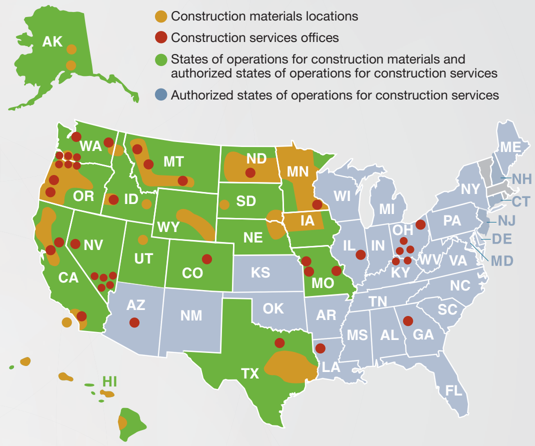
2015 Key Statistics

Revenues (millions)	
Electric	$280.6
Natural gas	$817.4
Earnings (millions)	
Electric	$35.9
Natural gas	$23.6
Electric retail sales (million kWh)	3,316.0
Natural gas distribution (MMdk)	
Sales	95.6
Transportation	154.2

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. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and supplies.

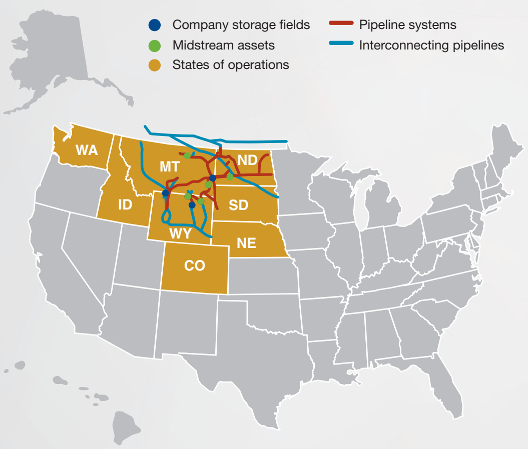


2015 Key Statistics

Revenues (millions)	
Construction materials	$1,904.3
Construction services	$926.4
Adjusted earnings (millions)	
Construction materials	$90.6
Construction services	$25.2
Construction materials sales (thousands)	
Aggregates (tons)	26,959
Asphalt (tons)	6,705
Ready-mix concrete (cubic yards)	3,592
Construction materials aggregate reserves (billion tons)	1.0

Pipeline and Midstream

WBI Energy 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 also provides cathodic protection and other energy-related services.



2015 Key Statistics

Revenues (millions)	$156.2
Adjusted earnings (millions)	$23.9
Pipeline (MMdk)	
Transportation	290.5
Gathering	33.4

Refining

Dakota Prairie Refining refines crude oil and produces and sells diesel fuel, naphtha, atmospheric tower bottoms and other byproducts.

2015 Key Statistics

Revenues (millions)	$178.3
Adjusted loss* (millions)	$(20.5)
Refined product sales (MBbl)	
Diesel fuel	1,072
Naphtha	996
Atmospheric tower bottoms and other	884

*Reflects the company's portion

Note: The revenues and adjusted earnings (loss) noted on this page exclude discontinued operations, the other category and intercompany eliminations. For GAAP revenues and earnings and for a discussion of adjustments to GAAP earnings, see page 1.

Report to Stockholders

Our company enters 2016 with good momentum and prepared to build upon the notable achievements by several of our business units last year. Although we remain optimistic about the opportunities for growth that we have identified, we recognize the most important measure of success for our shareholders is financial performance.

We are not satisfied with the company's 2015 results.

Adjusted earnings last year were $180.0 million, or 92 cents per share, compared to $205.5 million, or $1.07 per share in 2014.

On a Generally Accepted Accounting Principles (GAAP) basis, the company reported a loss of $623.1 million, or $3.20 per share, compared to 2014 earnings of $297.5 million, or $1.55 per share. Most of that loss occurred in the first three quarters of 2015 and is largely associated with our oil and gas business, Fidelity Exploration & Production, and our decision to exit that business.

We have nearly completed the sale of Fidelity's assets. We have closed on the sale of four asset packages, have a signed purchase and sale agreement for one of two remaining asset packages and are marketing the final.

With this behind us, our priorities will continue to be on the metrics important to our shareholders — financial results, stock price and dividends. Every one of our businesses is committed to earnings growth, although in some instances the commodity markets will continue to be challenging. We expect that improvement in our stock price will to a large degree reflect our earnings performance. We also are working hard to help the market better understand the individual pieces of our diversified business model and value them more appropriately.

We remain committed to the dividend. In November, the Board of Directors increased the common stock dividend for the 25th consecutive year. We are extremely proud of this achievement, which has been matched by fewer than 100 of the 2,500-plus other U.S.-listed, dividend-paying companies. We have paid dividends uninterrupted for 78 years.

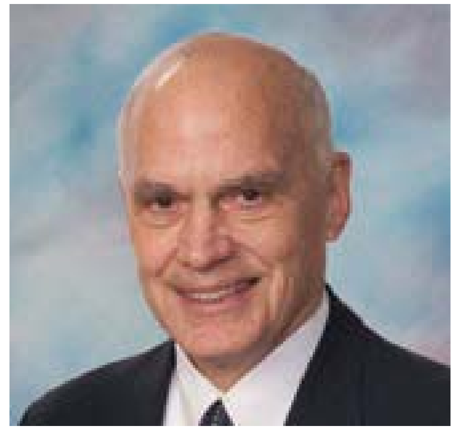
Construction materials business has record year

Our construction materials business, Knife River, had record adjusted earnings in 2015. Adjusted earnings increased 51 percent over 2014 on 8 percent revenue growth, which indicates that Knife River is doing an outstanding job of managing costs and margins. Aggregate and ready-mix volumes increased by 4 percent, asphalt volumes were up 11 percent, and margins were up across all product lines. Earnings increased in all of Knife River's regions, indicating solid markets across the 19 states in which they operate.

Knife River ended 2015 with a record backlog of $491 million, 12 percent higher than the prior year. Importantly, backlog remained relatively strong even in energy-driven markets where the economy is sensitive to oil drilling activity. Knife River started 2016 by adding to its record backlog with the largest contract in its history — a $63.4 million project to rebuild a portion of Interstate 29 in Sioux City, Iowa.

Bidding opportunities continue to improve in most markets. Looking ahead a bit, Knife River expects that in 2017 it will begin to see the benefits of the $305 billion, five-year highway bill that Congress passed in December to fund transportation infrastructure projects.

Our construction services business also enters 2016 with good momentum. It ended 2015 with a backlog of $493 million, 62 percent higher than the prior year and the highest year-end backlog since 2008. This reflects a successful year in which its priority was rebuilding work orders to replace several completed higher-margin projects that contributed to two consecutive years of record earnings in 2013 and 2014. The backlog includes outside electrical work, industrial, petrochemical, mission critical and solar contracts.



Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

Customer growth continues for utility

Continued customer growth of nearly 2 percent in 2015 has pushed our utility's total customer base to about 1,050,000 customers. The growth was spread across all eight states served by the utility and remained strong in North Dakota's Bakken, where the utility serves communities surrounding the oilfields, but not the wells themselves. This growth likely is due to residents using a temporary decline in drilling activity to transition from temporary to permanent housing in communities served by our utility. The utility expects continued customer growth of about 1.5 to 2 percent.

The utility invested a record $464 million in 2015 to accommodate customer growth and ensure the reliability and integrity of its transmission and distribution systems. This includes acquisition of the Thunder Spirit wind farm in southwestern North Dakota, which became fully operational in December. With the addition of this 43-turbine, 107.5-megawatt facility, 20 percent of the utility's electric generation capacity is renewable energy. The utility also added 19 MW of natural gas-fired generation at the Lewis & Clark plant near Sidney, Montana, and completed installation of a $384 million air quality control system at the Big Stone, South Dakota, generating plant that is owned jointly with two partners.

The utility is working hard to recover these investments through rate proceedings. Since the beginning of 2015, the utility has implemented $28.5 million in final rates and $20.8 million in interim rates, and has a number of additional rate cases pending in 2016. Revenue from rate case proceedings helped offset weather-related lower natural gas retail sales and lower residential electric retail sales. Temperatures in 2015 ranged from approximately 6 to 16 percent warmer than the previous year across the eight-state service territory.

The utility has been evaluating the Environmental Protection Agency's Clean Power Plan, which would require significant reductions in carbon dioxide emissions at its generating facilities. Although it is too early to determine specific cost impacts, we believe the plan as currently written will increase customer bills significantly.

We are working closely with state governments and agencies to identify potential implementation plans and are encouraging states to enter into regional solutions if the plan ultimately takes effect. The plan is the subject of legal challenges, and in February 2016 the U.S. Supreme Court temporarily blocked implementation of the plan until those challenges are fully litigated.

Pipeline business has record transportation volumes

The pipeline and midstream business had record transportation volumes on its natural gas pipeline system for the third consecutive year. The majority of its pipeline volumes are under fixed-fee firm contracts, and therefore are less sensitive to the commodity pricing environment that is affecting activity in the Bakken. However, gas gathering volumes decreased significantly as producers reacted to the lower price environment, and the 50 percent-owned Pronghorn facility experienced lower processing revenue.

The pipeline and midstream business is continuing to grow its traditional northern Rockies base through two expansion projects that are expected to be completed this year. The North Badlands and Northwest North Dakota projects will connect third-party processing facilities to interstate pipelines and add 88,000 dekatherms per day of capacity.

In addition, the business is evaluating potential expansion into other basins, such as the Marcellus, Utica and Permian, possibly through acquisition opportunities.

Commodity prices impact refinery

The Dakota Prairie refinery, which began commercial operations in May, operated at a loss in 2015 as the result of dramatic changes in the oil commodity market. The company has a 50 percent ownership interest in the refinery, which can process up to 20,000 barrels per day of oil into diesel fuel and several byproducts.

The Bakken basis differential from West Texas Intermediate pricing has narrowed, which has increased the refinery's cost for its oil feedstock. At the same time, reduced oilfield activity has decreased the demand for diesel fuel and a slowdown in Canadian tar sands development has reduced the demand for naphtha, one of the refinery's byproducts. The company continues to focus on operational improvements to the plant that could increase its daily processing capacity and profitability. However, we expect the unfavorable commodity price environment will continue to significantly impact the refinery in 2016.

Operationally, our businesses are performing very well, and we want to thank our employees for that accomplishment. We can assure you that our employees work hard to serve our shareholders and customers with operational excellence, safety and integrity.

Thank you, as well, for your investment in MDU Resources. We recognize that the company's performance in 2015 has fallen short of your expectations; it fell short of ours, too. Please know that we, along with our entire management team and Board of Directors, are committed to delivering better results.

Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

February 19, 2016

Board of Directors

Harry J. Pearce
73 (19)
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
54 (3)
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
66 (21)
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
62 (11)
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
63 (3)
Denver, Colorado

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

Expertise: Energy industry, business management, accounting and finance

A. Bart Holaday
73 (8)
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: Energy industry, business development, finance and law

Dennis W. Johnson
66 (15)
Dickinson, North Dakota

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

Expertise: Business management, engineering and finance

William E. McCracken
73 (3)
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, technology and cybersecurity

Patricia L. Moss
62 (13)
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

John K. Wilson
61 (13)
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

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2015.

Corporate Management

David L. Goodin
54 (33)

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
60 (30)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River

Martin A. Fritz
51 (1)

President and Chief Executive Officer of WBI Holdings, Inc.

Formerly an executive with a natural gas production and midstream company

Dennis L. Haider
63 (38)

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.

Anne M. Jones
52 (34)

Vice President of Human Resources of MDU Resources

Formerly vice president of human resources, customer service and safety of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Nicole A. Kivisto
42 (21)

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

Daniel S. Kunz
62 (12)

General Counsel and Secretary of MDU Resources

Serves as general counsel and secretary of all major subsidiary companies; formerly associate general counsel and assistant secretary of MDU Resources

Cynthia J. Norland
61 (32)

Vice President of Administration of MDU Resources

Formerly associate general counsel of MDU Resources

Doran N. Schwartz
46 (11)

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
53 (12)

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

Formerly held executive and management positions with MDU Construction Services Group

Other Corporate and Senior Company Officers

Nathan W. Ring, 40 (15)
Vice President, Controller and Chief Accounting Officer of MDU Resources

Jason L. Vollmer, 38 (11)
Treasurer and Director of Cash and Risk Management of MDU Resources

Management Changes

Martin A. Fritz was hired as president and chief executive officer of WBI Holdings, Inc., effective July 20, 2015. He replaces **Steven L. Bietz**, who retired July 17, 2015.

Anne M. Jones was named vice president of human resources of MDU Resources, effective January 1, 2016. She replaces **Mark A. Del Vecchio**, who resigned October 20, 2015.

Daniel S. Kuntz was named general counsel and secretary of MDU Resources, effective January 9, 2016. He replaces **Paul K. Sandness**, who retired January 8, 2016.

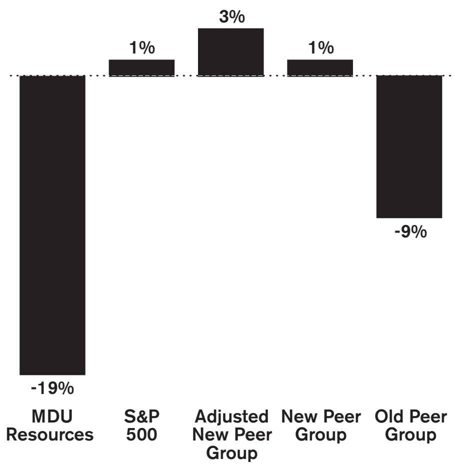
Patrick L. O'Bryan resigned from his position as president and chief executive officer of Fidelity Exploration & Production Company, effective February 29, 2016.

Numbers indicate age and years of service ( ) as of December 31, 2015.

Stockholder Return Comparison

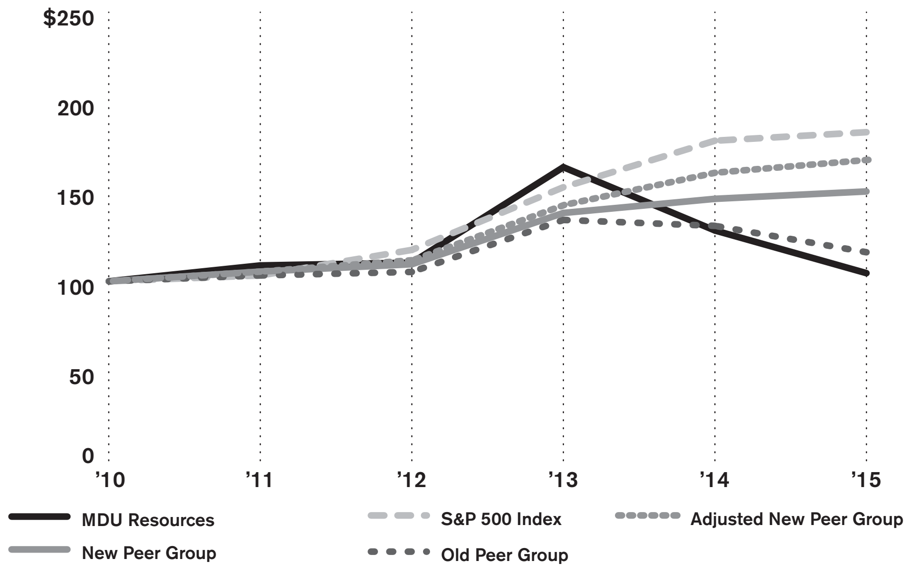
Comparison of One-Year Total Stockholder Return

(as of December 31, 2015)



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

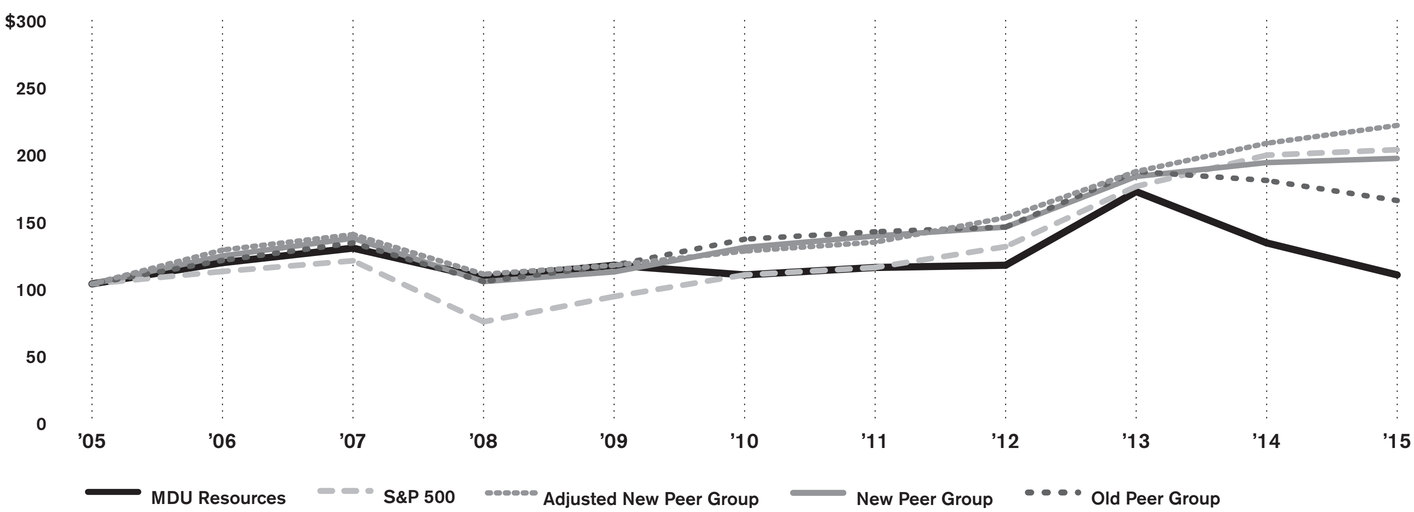
$100 invested December 31, 2010, in MDU Resources was worth $104.96 at year-end 2015.



	2010	2011	2012	2013	2014	2015
MDU Resources Group, Inc.	$100.00	$109.14	$111.41	$164.37	$129.55	$104.96
S&P 500 Index	100.00	102.11	118.45	156.82	178.29	180.75
Adjusted New Peer Group	100.00	104.17	117.26	143.36	163.41	168.91
New Peer Group	100.00	104.86	111.98	140.11	149.67	151.08
Old Peer Group	100.00	102.01	106.71	138.38	132.37	120.10

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

$100 invested December 31, 2005, in MDU Resources was worth $110.80 at year-end 2015.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
MDU Resources Group, Inc.	$100.00	$120.10	$131.93	$105.46	$119.06	$105.56	$115.22	$117.61	$173.52	$136.76	$110.80
S&P 500 Index	100.00	115.79	122.16	76.96	97.33	111.99	114.35	132.65	175.62	199.66	202.42
Adjusted New Peer Group	100.00	128.93	139.06	109.86	118.85	130.47	135.91	152.99	187.04	213.21	220.37
New Peer Group	100.00	125.15	136.20	104.80	116.13	131.44	137.83	147.19	184.16	196.73	198.58
Old Peer Group	100.00	122.59	137.10	103.36	118.55	135.62	138.34	144.72	187.67	179.52	162.88

Stockholder Return Comparison

Data is indexed to December 31, 2014, for the one-year total stockholder return comparison, December 31, 2010, for the five-year total stockholder return comparison and December 31, 2005, 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.

Effective January 1, 2015, a new peer group was established. Changes were made to increase utility, pipeline and construction companies and reduce the number of exploration and production companies, as the company reduced investment in and looked to the potential marketing of that business segment. It was determined when the new peer group was established that if the exploration and production business segment was sold, the remaining two exploration and production companies also would be removed from the peer group. Accordingly, when the closing of the sale of not less than 75 percent of the assets of Fidelity Exploration & Production Company occurred in December 2015, the remaining two exploration and production companies in the peer group, Bill Barrett Corporation and SM Energy Company, were removed from the peer group effective as of the end of day on November 30, 2015. These changes were made to better reflect the nature of the company's business and its mix of assets and sales. The graphs show stockholder return performance for the old, new and adjusted new peer groups.

Effective as of the end of the day on November 30, 2015, the adjusted new peer group issuers are ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Avista Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, IDACORP, Inc., Integrated Electrical Services, Inc., Martin Marietta Materials, Inc., MYR Group Inc., National Fuel Gas Company, Northwest Natural Gas Company, NorthWestern Corporation, Quanta Services, Inc., Questar Corporation, Sterling Construction Company, Inc., U.S. Concrete, Inc., Vectren Corporation and Vulcan Materials Company.

Effective January 1, 2015, the new peer group issuers were ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Avista Corporation, Bill Barrett Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, IDACORP, Inc., Integrated Electrical Services, Inc., Martin Marietta Materials, Inc., MYR Group Inc., National Fuel Gas Company, Northwest Natural Gas Company, NorthWestern Corporation, Quanta Services, Inc., Questar Corporation, SM Energy Company, Sterling Construction Company, Inc., U.S. Concrete, Inc., Vectren Corporation and Vulcan Materials Company.

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

During 2015, MarkWest Energy Partners, L.P., which was added in 2015 as a new peer group issuer, merged with another company. As a result, the company was not included in the performance graphs for either the new or adjusted new peer groups.

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, 2015

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 ☐ (Do not check if a smaller reporting company)	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, 2015: $3,805,857,581.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 11, 2016: 195,265,744 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's 2016 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Part I

Part II

Part III

Part IV

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
ATBs	Atmospheric tower bottoms
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)
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
Bombard Mechanical	Bombard Mechanical, LLC, an indirect wholly owned subsidiary of MDU Construction Services
BPD	Barrels per day
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Btu	British thermal unit
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 Court of Appeals	Court of Appeals, State of Colorado
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
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 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
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
ESCP	Erosion and Sediment Control Plan
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 (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America

Definitions

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
IFRS	International Financial Reporting Standards
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
LTM	LTM, Incorporated, an indirect wholly owned subsidiary of Knife River
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 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
Nevada State District Court	District Court Clark County, Nevada
NGL	Natural gas liquids
Notice of Civil Penalty	Notice of Civil Penalty Assessment and Order
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
Proxy Statement	Company's 2016 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act

RIN	Renewable Identification Number
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States 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
South Dakota DENR	South Dakota Department of Environment and Natural Resources
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
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
United States Supreme Court	Supreme Court of the United States
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
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, Knife River, MDU Construction Services, Centennial Resources and Centennial Capital. WBI Holdings is comprised of the pipeline and midstream segment; Dakota Prairie Refinery, which is reflected in the refining segment; and Fidelity, the Company's exploration and production business. For more information on Dakota Prairie Refinery, see Item 8 - Note 17. Knife River is the construction materials and contracting segment, MDU Construction Services is the construction services segment, and Centennial Resources and Centennial Capital are both reflected in the Other category.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets. Therefore, Fidelity's results are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category. For more information on the Company's business segments and discontinued operations, see Item 8 - Notes 2 and 13.

As of December 31, 2015, the Company had 8,689 employees with 149 employed at MDU Resources Group, Inc., 1,027 at Montana-Dakota, 34 at Great Plains, 317 at Cascade, 239 at Intermountain, 530 at WBI Holdings, 2,945 at Knife River and 3,448 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, 2015.

At Montana-Dakota and WBI Energy Transmission, 354 and 76 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2018, and March 31, 2018, respectively.

At Cascade, 179 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2018.

At Intermountain, 126 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 455 of its construction materials employees. Knife River is in negotiations on four of its labor contracts.

MDU Construction Services has 155 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 13 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 17. 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 refining 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 142,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2015. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 13 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 73 transmission and 318 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, 2015, Montana-Dakota's net electric plant investment was $1.3 billion.

The percentage of Montana-Dakota's 2015 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 65 percent; Montana - 21 percent; Wyoming - 9 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 611,542 kW in August 2015. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the sales growth rate through 2020 will approximate three percent annually. The interconnected system consists of 12 electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 704,143 kW and total net ZRCs of 513.2 in 2015. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2015, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 547.3. Montana-Dakota's planning reserve margin requirement within MISO was 547.3 for 2015. Montana-Dakota's interconnected system electric generating capability includes four steam-turbine generating units using coal for fuel, three combustion turbine peaking stations, three wind electric generating facilities, a reciprocating internal combustion engine, a heat recovery electric generating facility and three small portable diesel generators.

In December 2015, construction was completed on a wind farm consisting of 43 wind turbines totaling 107.5 MW of electric generation. On December 30, 2015, Montana-Dakota purchased the wind farm from Thunder Spirit Wind, LLC, at a total cost of approximately $214 million including purchase price, internal costs and AFUDC with approximately $55 million already funded in 2014. The project began commercial operation in the fourth quarter of 2015. The generation interconnects at Montana-Dakota's substation near Hettinger, North Dakota. Montana-Dakota completed construction and commissioning of an 18.7 MW reciprocating internal combustion engine electric generation project at the existing Lewis & Clark generating facility in Sidney, Montana in December of 2015. Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2015, Montana-Dakota purchased approximately 47 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)	2015 ZRCs (a)	2015 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	92.7	481,995
Heskett	Steam	86,000	87.2	500,630
Heskett	Combustion Turbine	89,038	70.8	1,211
Glen Ullin	Heat Recovery	7,500	3.4	38,248
Cedar Hills	Wind	19,500	4.5	57,147
Diesel Units	Oil	5,475	3.6	9
Thunder Spirit	Wind	107,500	(c)	11,174
South Dakota:				
Big Stone (b)	Steam	94,111	98.8	303,844
Montana:				
Lewis & Clark	Steam	44,000	52.1	222,192
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	(c)	96
Glendive	Combustion Turbine	75,522	73.2	1,212
Miles City	Combustion Turbine	23,150	21.4	443
Diamond Willow	Wind	30,000	5.5	89,144
		704,143	513.2	1,707,345
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	190,815
		732,143	513.2	1,898,160

(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, December 2021 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.

The owners of Coyote Station, including Montana-Dakota, have 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 17.

The owners of Big Stone Station, including Montana-Dakota, have coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 500,000 tons in 2016 from Peabody Coalsales, LLC and 750,000 in 2016 and 2017 from Alpha Coal Sales Co., LLC both 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,		**2015**		2014		2013
Average cost of coal per MMBtu	**$**	**1.75**	$	1.74	$	1.73
Average cost of coal per ton	**$**	**25.41**	$	25.11	$	25.32

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-2017. 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 which are filed annually. For more information, see Item 8 - Note 4.

In North Dakota, Montana-Dakota recovers in rates the costs associated with environmental upgrades at Big Stone Station and Lewis & Clark 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. Montana-Dakota will utilize this rider mechanism for new generation until such time as the costs and investment are included in base rates. For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider. 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.

For more information on regulatory matters, see Item 8 - Note 16.

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 DENR in November 2013. Big Stone Station continues to operate under conditions of the Title V Operating Permit issued by the South Dakota DENR in June 2009. It is expected that a final renewed permit will be issued in 2016 with the completion of the BART air quality control system. Wygen III is allowed to operate under the facility's construction permit until the Title V Operating Permit is issued by the Wyoming

Department of Environmental Quality. The Title V Operating Permit application for Wygen III was submitted timely in January 2011, with the permit expected to be issued in 2016. The Title V Operating Permit renewal application for Lewis & Clark Station was submitted timely in February 2014 to the Montana DEQ and the permit was issued July 2015. The Title V Operating Permit renewal application for Heskett Station was submitted timely in August 2014 to the North Dakota Department of Health and the permit was issued July 2015. The Title V Operating Permits for the Miles City and Glendive stations expire in August 2016, and the renewal applications are expected to be submitted to the Montana DEQ in early 2016.

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 $46.0 million of environmental capital expenditures in 2015, largely for the installation of a BART air quality control system at the Big Stone Station. Environmental capital expenditures are estimated to be $14.8 million, $4.1 million and $2.8 million in 2016, 2017 and 2018, respectively. Projects for 2016 through 2018 include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals emission control equipment installation and anticipated costs for coal ash disposal at electric generating stations. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by future air emission regulations and coal ash management requirements, including the Clean Power Plan rule published by the EPA in October 2015. Montana-Dakota is evaluating the Clean Power Plan, which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. It is unknown at this time what each state will require for emissions limits or reductions from each of Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 2018. On February 9, 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought. Montana-Dakota has not included estimates for capital expenditures in 2016 through 2018 for the potential compliance requirements of the Clean Power Plan.

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 906,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2015, and provide natural gas transportation services to certain customers on the Company's systems. These services are provided through distribution systems aggregating approximately 19,100 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, 2015, the natural gas distribution operations' net natural gas distribution plant investment was $1.3 billion.

The percentage of the natural gas distribution operations' 2015 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 32 percent; Washington - 26 percent; North Dakota - 15 percent; Montana - 8 percent; Oregon - 8 percent; South Dakota - 6 percent; Minnesota - 3 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 through rate adjustments which are filed annually.

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

On December 28, 2015, the OPUC approved an extension of Cascade's decoupling mechanism until January 1, 2020, with an agreement that Cascade would initiate a review of the mechanism by September 30, 2019. 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 16.

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 2015. 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 2018.

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 an 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 17 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 Midstream

General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 4,000 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, 2015, its net plant investment was $363.4 million.

The nonregulated business of this segment owns and operates gathering facilities in Montana and Wyoming. In 2015, the Company sold its gathering facilities in Colorado. It also owns a 50 percent undivided interest in the Pronghorn assets located in western North Dakota, 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 800 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.

A majority of its pipeline and midstream 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 17.

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. 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 2015 represented 43 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, the expansion of its systems and 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 midstream 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 RCRA 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 as required by the National Environmental Policy Act are included in the FERC's environmental review process for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and midstream operations did not incur any material environmental expenditures in 2015 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2018.

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 17.

The construction materials business had approximately $491 million in backlog at December 31, 2015, compared to $438 million at December 31, 2014. The Company anticipates that a significant amount of the current backlog will be completed during 2016.

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 955 million tons of the 1.0 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 2013 through 2015. 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, 2015, and sales for the years ended December 31, 2015, 2014 and 2013:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves	Lease	Reserve Life
Production Area	owned	leased	owned	leased	**2015**	2014	2013	(000's tons)	Expiration	(years)
Anchorage, AK	—	—	1	—	**1,837**	1,665	1,074	17,315	N/A	11
Hawaii	—	6	—	—	**1,892**	1,840	1,672	53,992	2017-2064	30
Northern CA	—	—	9	1	**1,580**	1,340	1,525	52,204	2018	35
Southern CA	—	2	—	—	**118**	147	241	91,846	2035	Over 100
Portland, OR	1	3	5	3	**3,562**	3,244	3,343	225,148	2025-2055	67
Eugene, OR	3	4	4	—	**819**	928	825	155,566	2016-2046	Over 100
Central OR/WA/ID	1	1	5	4	**1,493**	1,254	1,045	113,867	2020-2077	90
Southwest OR	5	5	12	5	**1,872**	1,624	1,465	93,592	2017-2053	57
Central MT	—	—	1	2	**1,383**	1,260	1,236	26,094	2023-2027	20
Northwest MT	—	—	7	2	**1,423**	1,486	1,242	63,140	2016-2020	46
Wyoming	—	—	1	1	**888**	952	983	9,731	2019	10
Central MN	—	1	38	12	**2,556**	1,674	1,578	55,091	2016-2028	28
Northern MN	2	—	14	5	**595**	491	349	25,330	2016-2017	53
ND/SD	—	—	3	19	**1,959**	2,377	1,862	27,453	2016-2031	13
Texas	1	2	1	—	**1,138**	903	672	12,144	2022	13
Sales from other sources					**3,844**	4,642	5,601			
					26,959	25,827	24,713	1,022,513		

The 1.0 billion tons of estimated aggregate reserves at December 31, 2015, are comprised of 476 million tons that are owned and 547 million tons that are leased. Approximately 31 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 22 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2013 through 2015 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 61 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 were as follows:

	2015	2014	2013
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,061,156**	1,083,376	1,088,236
Acquisitions	**7,406**	12,343	22,682
Sales volumes*	**(23,115)**	(21,185)	(19,112)
Other**	**(22,934)**	(13,378)	(8,430)
End of year	**1,022,513**	1,061,156	1,083,376

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

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 the 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 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 2015 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 2018.

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 17.

In October 2015, the Oregon DEQ issued a Notice of Civil Penalty to LTM asserting violations of Oregon water quality statues and rules at a site in Coos County. For more information, see Item 8 - Note 17.

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 provides utility construction services specializing in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

For information regarding construction services litigation, see Item 8 - Note 17.

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, 2015, 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, 2015, was approximately $493 million compared to $305 million at December 31, 2014. MDU Construction Services expects to complete a significant amount of this backlog during 2016. 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 2015 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2018.

Refining

General WBI Energy, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. The refinery is designed as a 20,000-barrel-per-day facility located in the Bakken region in Stark County in western North Dakota.

Construction of the refinery was completed in March 2015 and the refinery began commercial operations in May 2015. The refinery processes Bakken crude oil into diesel, naphtha, ATBs and other by-products.

System Supply, System Demand and Competition Bakken crude oil is supplied to the refinery via a pipeline interconnect with the Belle Fourche Pipeline and a portion is trucked to the refinery from wells near the refinery. Crude oil contracts are generally secured on a month-to-month basis. Dakota Prairie Refining believes that adequate supplies of crude oil will continue to be available; however, more challenging to secure due to the slowdown in drilling activity in the Bakken region.

The refinery sells diesel fuel at the refinery rack to diesel wholesalers. Naphtha is railed to Canada and sold to third parties primarily for use as a diluent for tar sands production. ATBs are railed and sold to other facilities for further processing.

Dakota Prairie Refining's competitors include a number of large, integrated refiners with greater flexibility in responding to or absorbing market changes. Dakota Prairie Refining obtains all of its crude oil from third-party sources and competes with other purchasers in the local market area for these supplies. The availability and cost of crude oil, as well as the demand for and prices of the products the refining operations produce, are heavily influenced by global, as well as regional, supply and demand dynamics. Major competitors for the sale of Dakota Prairie Refining's refined products include other refineries both in the state and in the surrounding states that produce similar products.

Environmental Matters Refinery operations are subject to numerous federal, state and local laws regulating the discharge of substances into the environment or otherwise relating to the protection of the environment. Permits are required under these laws for the operation of refineries, pipelines and related refining operations facilities, and these permits are subject to revocation, modification and renewal. Compliance with applicable environmental laws, regulations and permits will continue to have an impact on refining operations, results of operations, and capital requirements. Dakota Prairie Refining believes that its current operations are in substantial compliance with applicable federal, state and local environmental laws, regulations and permits.

Dakota Prairie Refining's operations and many of the products it manufactures are subject to certain requirements of the Clean Air Act as well as related state and local laws and regulations. The EPA has the authority under the Clean Air Act to modify the formulation of the refined transportation fuel products Dakota Prairie Refining manufactures in order to limit the emissions associated with their final use. In addition, in 2014, the EPA published a proposed rule that proposes amendments to refinery standards already in effect: the National Emission Standards for Hazardous Air Pollutants from Petroleum. The proposed rule would also amend emission requirements under the existing Petroleum Refinery New Source Performance Standard. The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 prescribe certain percentages of renewable fuels (e.g., ethanol and biofuels) that, where required by the Renewable Fuel Standard, must be blended into the refining operations' produced diesel or that requirement may be satisfied by purchasing RINs. For more information on RINs, see Item 8 - Note 6. Dakota Prairie Refining's operations are also subject to the Clean Water Act, the Federal Safe Drinking Water Act and comparable state and local requirements. The Clean Water Act, the Federal Safe Drinking Water Act and analogous laws prohibit any discharge into surface waters, ground waters, injection wells and publicly owned treatment works except in conformance with legal authorization, such as pre-treatment permits and National Pollutant Discharge Elimination System permits, issued by federal, state and local governmental agencies. National Pollutant Discharge Elimination System permits and analogous water discharge permits are valid for a maximum of five years and must be renewed.

Compliance with current and future environmental regulations is not expected to require material capital expenditures through 2018.

Discontinued Operations

General Discontinued operations includes the results of Fidelity other than certain general and administrative costs and interest expense. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The completion of the majority of these sales occurred in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. For more information on discontinued operations, see Item 8 - Note 2 and Supplementary Financial Information.

For information regarding litigation from discontinued operations, see Item 8 - Note 17.

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 pipeline and midstream and refining businesses are dependent on factors, including commodity prices and commodity price basis differentials/crack spreads, 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/crack spreads; 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; and other risks incidental to the development and operations of oil and natural gas processing plants, pipeline systems and the refinery. Continued prolonged depressed prices for oil, NGL and natural gas could impede the growth of our pipeline and midstream business, and could negatively affect the results of operations, cash flows and asset values of the Company's pipeline and midstream and refining businesses.

The regulatory approval, permitting, construction, startup and/or operation of power generation facilities 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 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 supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power; cost increases and overruns; the risk of performance below expected levels of output or efficiency; and 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.

The operation of Dakota Prairie Refinery may involve events that could negatively impact the Company's business, its results of operations, cash flows and asset values.

The operation of Dakota Prairie Refinery involves many risks, which may include: breakdown or failure of the equipment and systems; inability to operate within environmental permit parameters; inability to produce refined products to required specifications; inability to obtain crude oil supply; inability to effectively manage distribution channels; changes in markets and market prices for crude oil and refined products; operating cost increases; and the inability of Dakota Prairie Refinery to fund its operations from its operating cash flows, by obtaining third-party financing or through capital contributions from Calumet or WBI Energy; as well as the risk of performance below expected levels of output or efficiency. Such events, as well as continued operating losses at Dakota Prairie Refinery, could negatively impact the Company's business, its results of operations, cash flows and asset values.

Economic volatility, including volatility in North Dakota's Bakken region, 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 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, retire and replace certain facilities, install pollution controls, remediate environmental impacts, remove or reduce environmental hazards, or forego or limit the development of resources. Revised or new 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.

On April 17, 2015, the EPA published a final rule, under the RCRA, for coal combustion residuals that regulates coal ash as a solid waste and not a hazardous waste. The rule requires ground water and location restriction evaluations be conducted by October 2017 at ash impoundments and landfills not located at coal mines. In 2015, one ash impoundment at Lewis & Clark Station was replaced with a new concrete basin. Additional site and groundwater analyses may identify the need to upgrade or close additional impoundments or the Company may need to install replacement ash management systems. The cost of replacement ash impoundments or landfills may be material. If these costs are not fully recoverable from customers, they could have a material adverse effect on the Company's results of operations and cash flows.

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 or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study that will be submitted to the Montana DEQ by July 31, 2019, to be used in determining any required controls. It is unknown at this time what controls may be 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.

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 October 23, 2015, the EPA published the final rule establishing carbon dioxide emission limits for new, reconstructed and modified coal-fired steam electric generating units. In this same rule, the EPA established carbon dioxide emission limits for new and reconstructed base load and non-base load stationary combustion turbines. At this time, the EPA has determined not to establish emission limits for modified stationary combustion turbines and has withdrawn the proposed rule emission standards for modified stationary combustion turbines. New coal-fired generating units must comply with an emission standard of 1,400 pounds of carbon dioxide per MW hour gross, equivalent to a super critical pulverized coal unit capturing about 20 percent of its carbon dioxide emissions. Unless carbon capture and storage technology becomes available and cost effective, no new coal-fired electric generating facilities are projected to be constructed. Limits for reconstructed and modified coal-fired generating units may preclude reconstruction or modification depending on the facility. New and reconstructed base load stationary natural gas-fired combustion turbines must comply with an emission standard of 1,000 pounds of carbon dioxide per MW hour gross which should be achievable, but could limit operating at higher load levels, depending on the unit. For newly constructed and reconstructed non-base load (peaking) natural gas-fired stationary combustion turbines, the EPA has established a heat input-based emission standard of 120 pounds of carbon dioxide per MMBtu.

On October 23, 2015, the EPA published the final Clean Power Plan rule which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. By September 6, 2016, states must either submit to the EPA a request for an extension to submit a final state plan by September 6, 2018, or submit a final plan. The state plan must demonstrate how emissions reductions will be achieved and include emission limits in the form of an annual emission cap or an emission rate that will be applied to each individual fossil fuel-fired electric generating facility starting in 2022. Emissions limits become more stringent from 2022 to 2030, with the 2030 emission limits applying thereafter. It is unknown at this time what each state will require for emissions limits or reductions from each of Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 6, 2018. On February 9, 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought.

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 50 percent of Montana-Dakota's owned generating capacity and approximately 90 percent of the electricity it generated in 2015 was from coal-fired facilities.

On January 14, 2015, President Obama announced a goal to reduce methane emissions from the oil and natural gas industry by 40 to 45 percent below 2012 levels by 2025. On September 18, 2015, the EPA published a proposed rule on standards for methane and GHG emissions from new and modified sources within the oil and natural gas industry, with a final rule expected in 2016. The rule, as proposed, would require emission reductions and work practices for sources such as gathering and boosting stations, and transmission and storage compressor stations. The president will continue to evaluate further methods of methane reduction including additional leak detection controls and emission reporting, enhanced venting and flaring requirements for sources on public lands, and upgrades to existing natural gas transmission and distribution infrastructure. It is unknown at this time how the Company will be impacted or if compliance costs will be material.

On January 6, 2016, the Washington DOE issued the proposed Clean Air Rule, a rule requiring reductions of carbon dioxide emissions from various industries, including carbon dioxide emissions resulting from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. The rule requires reductions in carbon dioxide emissions resulting from the combustion of natural gas Cascade supplies to the majority of its customers. In 2017, the rule requires Cascade to hold carbon dioxide emissions to a baseline, equal to the average emissions in 2012 to 2016. Beginning in 2018, annual carbon dioxide emissions would be reduced by an additional one and two-thirds percent of the baseline from the previous year's emissions. Washington DOE proposes compliance to be achieved through emissions credit purchases using existing trading markets or by funding end-use energy efficiency projects that would reduce natural gas usage, increasing the operating costs for Cascade. If Cascade could not receive timely and full recovery of compliance costs from its customers, such costs could adversely impact the results of its operations.

There also may 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 or impose conditions on an acquisition of or by 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, rate structures, health care coverage and cost, taxes, franchises 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 as well as for acquisitions by 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 activities for the pipeline and midstream and refining businesses. In addition, severe weather can be destructive, causing outages, 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 exists in all of the Company's businesses.

All of the Company's businesses are subject to 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 and other factors. The pipeline and midstream business competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The refining business competes with larger and more diverse refineries that may be better positioned to withstand volatile industry and pricing conditions. 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.

Cost increases 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 $16.4 million (approximately $9.8 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, theft, sabotage, viruses, acts of terrorism, acts of war 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 processing facilities, storage and pipeline systems, may be unable to fulfill critical business functions, including an inability to produce or distribute some part of our energy services and other products and the provision of service to customers. Such disruption could result in decreased 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 with other operators, a disruption elsewhere in the system could negatively impact the Company's business.

The Company's business requires access to sensitive customer, employee, shareholder 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 has completed the sale of the majority of Fidelity's assets and is currently marketing the remaining assets of Fidelity, there is no assurance that a sale of the remaining marketed assets will be successful, and Fidelity may continue to be subject to potential liabilities relating to the sold assets arising from events prior to sale.

As part of the Company’s corporate strategy, it sold the majority of its Fidelity assets, and is currently marketing the remaining assets and will exit that line of business. Such a disposition of the remaining assets is subject to various risks, including: the purchase and sale agreements may be terminated prior to closing as a result of the due diligence process or due to inability of the purchasers to obtain financing; suitable purchasers may not be available or willing to purchase the remaining assets on terms and conditions acceptable to the

Company; the agreements pursuant to which the Company divests the assets may contain continuing indemnification obligations; the Company may incur costs in connection with the marketing and sale of the assets; there could be tax consequences dependent on the nature of the sale; and the Company may be required to record additional fair value impairment charges that could have an adverse effect on the Company’s financial condition. Fidelity will also continue to be subject to potential liabilities, either directly or through indemnification of buyers, for potential liabilities relating to the sold assets arising from events prior to sale.

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 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 17, 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 2015 and 2014 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2015			
First quarter	**$24.51**	**$20.01**	**$.1825**
Second quarter	**23.12**	**19.22**	**.1825**
Third quarter	**19.73**	**16.15**	**.1825**
Fourth quarter	**19.66**	**16.26**	**.1875**
			$.7350
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

As of December 31, 2015, the Company's common stock was held by approximately 12,900 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 10.

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, 2015	—			
November 1 through November 30, 2015	54,351	$18.21		
December 1 through December 31, 2015	3,830	16.97		
Total	58,181			

(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

	2015	2014	2013	2012	2011	2010
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 280,615**	$ 277,874	$ 257,260	$ 236,895	$ 225,468	$ 211,544
Natural gas distribution	**817,419**	921,986	851,945	754,848	907,400	892,708
Pipeline and midstream	**156,236**	157,365	144,571	142,610	152,972	175,961
Construction materials and contracting	**1,904,282**	1,765,330	1,712,137	1,617,425	1,510,010	1,445,148
Construction services	**926,427**	1,119,529	1,039,839	938,558	854,389	789,100
Refining	**178,262**	—	—	—	—	—
Other	**9,191**	9,364	9,620	10,370	11,446	7,727
Intersegment eliminations	**(80,883)**	(136,632)	(95,201)	(74,595)	(68,482)	(49,125)
	$ 4,191,549	$ 4,114,816	$ 3,920,171	$ 3,626,111	$ 3,593,203	$ 3,473,063
Operating income (loss) (000's):						
Electric	**$ 57,955**	$ 61,331	$ 54,274	$ 49,852	$ 49,096	$ 48,296
Natural gas distribution	**53,810**	65,633	78,829	67,579	82,856	75,697
Pipeline and midstream	**29,988**	46,713	20,896	49,139	45,365	46,310
Construction materials and contracting	**146,026**	86,462	93,629	57,864	51,092	63,045
Construction services	**43,376**	82,309	85,246	66,531	39,144	33,352
Refining	**(68,860)**	(9,097)	(850)	—	—	—
Other	**(5,700)**	(4,028)	(4,146)	(5,325)	(7,079)	(10,854)
Intersegment eliminations	**(2,462)**	(9,900)	(7,176)	—	—	—
	$ 254,133	$ 319,423	$ 320,702	$ 285,640	$ 260,474	$ 255,846
Earnings (loss) on common stock (000's):						
Electric	**$ 35,914**	$ 36,731	$ 34,837	$ 30,634	$ 29,258	$ 28,908
Natural gas distribution	**23,607**	30,484	37,656	29,409	38,398	36,944
Pipeline and midstream	**13,250**	24,666	7,701	26,588	23,082	23,208
Construction materials and contracting	**89,096**	51,510	50,946	32,420	26,430	29,609
Construction services	**23,762**	54,432	52,213	38,429	21,627	17,982
Refining	**(22,457)**	(2,038)	(72)	—	—	—
Other	**(12,376)**	(7,317)	(10,605)	(7,209)	(5,918)	8,508
Intersegment eliminations	**(1,531)**	(6,095)	(4,307)	—	—	—
Earnings on common stock before income (loss) from discontinued operations	**149,265**	182,373	168,369	150,271	132,877	145,159
Income (loss) from discontinued operations, net of tax*	**(772,385)**	115,175	109,879	(151,710)	79,464	94,815
	$ (623,120)	$ 297,548	$ 278,248	$ (1,439)	$ 212,341	$ 239,974
Earnings (loss) per common share before discontinued operations - diluted	**$ .77**	$ .95	$ .89	$ .80	$ .70	$ .77
Discontinued operations, net of tax	**(3.97)**	.60	.58	(.81)	.42	.50
	$ (3.20)	$ 1.55	$ 1.47	$ (.01)	$ 1.12	$ 1.27
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	**194,986**	192,587	189,693	188,826	188,905	188,229
Dividends declared per common share	**$ .7350**	$ .7150	$ .6950	$ .6750	$ .6550	$ .6350
Book value per common share	**$ 12.83**	$ 16.66	$ 15.01	$ 13.95	$ 14.62	$ 14.22
Market price per common share (year end)	**$ 18.32**	$ 23.50	$ 30.55	$ 21.24	$ 21.46	$ 20.27
Market price ratios:						
Dividend payout**	**95%**	75%	78%	84%	94%	82%
Yield	**4.1%**	3.1%	2.3%	3.2%	3.1%	3.2%
Market value as a percent of book value	**142.8%**	141.1%	203.5%	152.3%	146.8%	142.5%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) and $246.8 million (after tax) in 2015 and 2012, respectively, and fair value impairments of assets held for sale of $475.4 million (after tax) in 2015.

** Based on continuing operations.

Item 6. Selected Financial Data (continued)

	2015	2014	2013	2012	2011	2010
General						
Total assets (000's)	**$ 6,627,608**	$ 7,832,408	$ 7,073,447	$ 6,708,666	$ 6,583,597	$ 6,310,976
Total long-term debt (000's)	**$ 1,871,232**	$ 2,093,830	$ 1,853,112	$ 1,743,000	$ 1,422,207	$ 1,503,813
Capitalization ratios:						
Common equity	**57%**	61%	60%	60%	66%	64%
Total debt	**43**	39	40	40	34	36
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,316,017**	3,308,358	3,173,086	2,996,528	2,878,852	2,785,710
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**547.3**	584.0	583.5	552.8	572.8	553.3
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	**547.3**	522.4	508.3	550.7	524.2	529.5
Demand peak - kW (Interconnected system)	**611,542**	582,083	573,587	573,587	535,761	525,643
Electricity produced (thousand kWh)	**1,898,160**	2,519,938	2,430,001	2,299,686	2,488,337	2,472,288
Electricity purchased (thousand kWh)	**1,658,002**	1,010,422	971,261	870,516	645,567	521,156
Average cost of fuel and purchased power per kWh	**$ .024**	$ .025	$ .025	$ .023	$ .021	$ .021
Natural Gas Distribution						
Sales (Mdk)	**95,559**	104,297	108,260	93,810	103,237	95,480
Transportation (Mdk)	**154,225**	145,941	149,490	132,010	124,227	135,823
Degree days (% of normal)						
Montana-Dakota/Great Plains	**88%**	103%	105%	84%	101%	98%
Cascade	**83%**	89%	98%	96%	103%	96%
Intermountain	**89%**	95%	110%	91%	107%	100%
Pipeline and Midstream						
Transportation (Mdk)	**290,494**	233,483	178,598	137,720	113,217	140,528
Gathering (Mdk)	**33,441**	38,372	40,737	47,084	66,500	77,154
Customer natural gas storage balance (Mdk)	**16,600**	14,885	26,693	43,731	36,021	58,784
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**26,959**	25,827	24,713	23,285	24,736	23,349
Asphalt (tons)	**6,705**	6,070	6,228	5,988	6,709	6,279
Ready-mixed concrete (cubic yards)	**3,592**	3,460	3,223	3,157	2,864	2,764
Aggregate reserves (000's tons)	**1,022,513**	1,061,156	1,083,376	1,088,236	1,088,833	1,107,396
Refining						
Refined product sales (MBbls)						
Diesel fuel	**1,072**	*	*	*	*	*
Naphtha	**996**	*	*	*	*	*
ATBs and other	**884**	*	*	*	*	*
Total refined product sales	**2,952**	*	*	*	*	*

* Dakota Prairie Refinery began commercial operation in 2015.

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 businesses, see Item 8 - Note 13.

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 is 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 Midstream

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, and investments in and acquisitions of energy-related assets and companies both in its current operating areas and beyond its northern Rockies base. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing gathering and transmission facilities; incremental expansion of pipeline capacity; expansion of the pipeline and midstream business to include liquid pipelines and processing activities; and expansion of related energy services.

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

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, are ongoing challenges. 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 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.

Refining

Strategy Utilize Dakota Prairie Refinery’s prime location in North Dakota’s Bakken region to access crude oil supplies to safely and efficiently produce into refined products. Pursue operational effectiveness to maximize returns and cash flows through efforts such as marketing, cost reductions and refinery performance improvements. Additional opportunities exist in debottlenecking the plant which could increase production volumes.

Challenges Challenges for this market include the narrowing of the differential between the Company’s actual crude oil price and West Texas Intermediate crude oil prices; availability, cost and price volatility of crude oil and refined products; narrowing crack spreads for refined products including diesel, naphtha and ATBs; changes in overall demand for refined products; environmental and regulatory requirements; the potential for increasing price volatility for RINs and competition from other refineries.

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,	**2015**	2014	2013
	(Dollars in millions, where applicable)		
Electric	**$ 35.9**	$ 36.7	$ 34.8
Natural gas distribution	**23.6**	30.5	37.7
Pipeline and midstream	**13.3**	24.7	7.7
Construction materials and contracting	**89.1**	51.5	50.9
Construction services	**23.8**	54.5	52.2
Refining	**(22.5)**	(2.1)	(.1)
Other	**(12.4)**	(7.2)	(10.6)
Intersegment eliminations	**(1.5)**	(6.2)	(4.3)
Earnings before discontinued operations	**149.3**	182.4	168.3
Income (loss) from discontinued operations, net of tax	**(772.4)**	115.1	109.9
Earnings (loss) on common stock	**$ (623.1)**	$ 297.5	$ 278.2
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	**$ .77**	$ .95	$ .89
Discontinued operations, net of tax	**(3.97)**	.60	.58
Earnings (loss) per common share - basic	**$ (3.20)**	$ 1.55	$ 1.47
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	**$ .77**	$ .95	$ .89
Discontinued operations, net of tax	**(3.97)**	.60	.58
Earnings (loss) per common share - diluted	**$ (3.20)**	$ 1.55	$ 1.47

2015 compared to 2014 The Company recognized a consolidated loss of $623.1 million in 2015, compared to consolidated earnings of $297.5 million in 2014. This decrease was due to:

- Discontinued operations which had a fair value impairment of the Company's assets held for sale of $475.4 million (after tax); a $315.3 million after-tax noncash write-down of oil and natural gas properties; lower average realized commodity prices, excluding gain/loss on commodity derivatives; and decreased oil production; partially offset by lower depreciation, depletion and amortization expense and lease operating expense
- Lower workloads and margins in the Western region and lower equipment rental sales and margins at the construction services business
- Higher operation and maintenance, largely due to higher rail-related and contract services costs with commencement of operations of Dakota Prairie Refinery occurring in May 2015
- Impairments of natural gas gathering assets of $10.6 million (after tax) at the pipeline and midstream business
- Higher depreciation, depletion and amortization expense due to plant additions and lower natural gas sales volumes offset in part by natural gas retail rate increases at the natural gas distribution business

Partially offsetting these decreases were higher earnings on all product lines at the construction materials and contracting business.

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 at the pipeline and midstream business
- Other earnings 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.

Financial and Operating Data

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

Electric

Years ended December 31,	2015	2014	2013
	(Dollars in millions, where applicable)		
Operating revenues	**$ 280.6**	$ 277.9	$ 257.3
Operating expenses:			
Fuel and purchased power	**86.2**	89.3	83.5
Operation and maintenance	**87.7**	81.1	76.5
Depreciation, depletion and amortization	**37.6**	35.0	32.8
Taxes, other than income	**11.1**	11.1	10.2
	222.6	216.5	203.0
Operating income	**58.0**	61.4	54.3
Earnings	**$ 35.9**	$ 36.7	$ 34.8
Retail sales (million kWh)	**3,316.0**	3,308.4	3,173.1
Average cost of fuel and purchased power per kWh	**$ .024**	$ .025	$ .025

2015 compared to 2014 Electric earnings decreased $800,000 (2 percent) compared to the prior year due to:

- Higher operation and maintenance expense, which includes $4.3 million (after tax) largely related to higher contract services, primarily related to a planned outage at an electric generation station, and higher payroll and benefit-related costs
- Higher depreciation, depletion and amortization expense of $1.6 million (after tax) due to increased property, plant and equipment balances
- Higher net interest expense, which includes $1.1 million (after tax) due to higher long-term debt

Partially offsetting these decreases were:

- Increased electric retail sales margins, primarily due to rate recovery of new generation

- Higher other income, which includes $3.5 million (after tax) primarily related to allowance for funds used during construction

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

Natural Gas Distribution

Years ended December 31,	**2015**	2014	2013
	(Dollars in millions, where applicable)		
Operating revenues	**$ 817.4**	$ 922.0	$ 851.9
Operating expenses:			
Purchased natural gas sold	**499.0**	603.2	534.8
Operation and maintenance	**153.5**	150.2	142.3
Depreciation, depletion and amortization	**64.8**	54.7	50.0
Taxes, other than income	**46.3**	48.3	46.0
	763.6	856.4	773.1
Operating income	**53.8**	65.6	78.8
Earnings	**$ 23.6**	$ 30.5	$ 37.7
Volumes (MMdk):			
Sales	**95.6**	104.3	108.3
Transportation	**154.2**	145.9	149.5
Total throughput	**249.8**	250.2	257.8
Degree days (% of normal)*			
Montana-Dakota/Great Plains	**88%**	103%	105%
Cascade	**83%**	89%	98%
Intermountain	**89%**	95%	110%
Average cost of natural gas, including transportation, per dk	**$ 5.22**	$ 5.78	$ 4.94

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

2015 compared to 2014 The natural gas distribution business experienced a decrease in earnings of $6.9 million (23 percent) compared to the prior year due to:

- Higher depreciation, depletion and amortization expense of $6.3 million (after tax), largely resulting from increased property, plant and equipment balances
- Lower natural gas sales margins, primarily lower retail sales volumes of 8 percent to all customer classes due to warmer weather than the prior year, partially offset by approved rate increases effective in 2015 and increased transportation volumes

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenue and purchased natural gas sold in 2015.

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

Pipeline and Midstream

Years ended December 31,		**2015**		2014		2013
		(Dollars in millions)				
Operating revenues	**$**	**156.2**	$	157.4	$	144.6
Operating expenses:						
Purchased natural gas sold		**1.2**		—		—
Operation and maintenance*		**84.8**		68.1		81.0
Depreciation, depletion and amortization		**28.0**		29.8		29.1
Taxes, other than income		**12.2**		12.8		13.6
		126.2		110.7		123.7
Operating income		**30.0**		46.7		20.9
Earnings*	**$**	**13.3**	$	24.7	$	7.7
Transportation volumes (MMdk)		**290.5**		233.5		178.6
Natural gas gathering volumes (MMdk)		**33.4**		38.4		40.7
Customer natural gas storage balance (MMdk):						
Beginning of period		**14.9**		26.7		43.7
Net injection (withdrawal)		**1.7**		(11.8)		(17.0)
End of period		**16.6**		14.9		26.7

* Reflects impairments of natural gas gathering assets of $17.1 million ($10.6 million after tax) in 2015 and coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax) in 2013, as discussed in Item 8 - Note 1; as well as a net benefit of $2.5 million ($1.5 million after tax) in 2013 related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Item 8 - Note 17.

2015 compared to 2014 Pipeline and midstream earnings decreased $11.4 million (46 percent) largely due to:

- Impairment of natural gas gathering assets of $10.6 million (after tax) included in operation and maintenance expense, as discussed in Item 8 - Note 1
- Lower gathering and processing earnings of $5.2 million (after tax), primarily lower processing prices and natural gas gathering volumes
- Lower storage services earnings, primarily due to lower interruptible storage withdrawal volumes and lower average balances

Partially offsetting the earnings decrease was higher earnings of $5.7 million (after tax) due to higher transportation revenue, primarily resulting from higher rates due to a rate case settlement effective in May 2014, and increased volumes.

2014 compared to 2013 Pipeline and midstream earnings increased $17.0 million (220 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 $1.0 million of higher income tax benefits
- Lower operation and maintenance expense (excluding the asset impairment, net benefit related to natural gas gathering operations litigation and Pronghorn-related expense), which includes $800,000 (after tax) largely related to legal and abandonment costs offset in part by higher payroll and benefit-related costs

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
- 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 17

Construction Materials and Contracting

Years ended December 31,		2015		2014		2013
			(Dollars in millions)			
Operating revenues	$	**1,904.3**	$	1,765.3	$	1,712.1
Operating expenses:						
Operation and maintenance*		**1,652.3**		1,571.5		1,505.2
Depreciation, depletion and amortization		**65.9**		68.6		74.5
Taxes, other than income		**40.1**		38.8		38.8
		1,758.3		1,678.9		1,618.5
Operating income		**146.0**		86.4		93.6
Earnings*	$	**89.1**	$	51.5	$	50.9
Sales (000's):						
Aggregates (tons)		**26,959**		25,827		24,713
Asphalt (tons)		**6,705**		6,070		6,228
Ready-mixed concrete (cubic yards)		**3,592**		3,460		3,223

* Reflects a MEPP withdrawal liability of approximately $2.4 million ($1.5 million after tax) in first quarter 2015 and $14.0 million ($8.4 million after tax) in fourth quarter 2014. For more information, see Item 8 - Note 14.

2015 compared to 2014 Earnings at the construction materials and contracting business increased $37.6 million (73 percent) due to:

- Higher earnings of $9.1 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings of $7.2 million (after tax) resulting from higher asphalt margins and volumes, which includes lower asphalt oil costs
- A MEPP withdrawal liability of $1.5 million (after tax) in 2015, compared to $8.4 million (after tax) in 2014, as discussed in Item 8 - Note 14
- Higher earnings of $6.1 million (after tax) resulting from higher construction revenues and margins including the effects of favorable weather
- Higher earnings of $1.6 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings resulting from higher other product line margins and volumes

Partially offsetting these increases were higher selling, general and administrative expense of $5.7 million (after tax), largely related to higher payroll-related and other costs.

Lower diesel fuel costs contributed to higher earnings from all product lines.

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 14
- Higher selling, general and administrative expense of $1.9 million (after tax), primarily due to higher payroll and benefit-related costs

Construction Services

Years ended December 31,		2015		2014		2013
				(In millions)		
Operating revenues	$	**926.4**	$	1,119.5	$	1,039.8
Operating expenses:						
Operation and maintenance		**838.5**		990.7		910.7
Depreciation, depletion and amortization		**13.4**		12.9		11.9
Taxes, other than income		**31.1**		33.6		32.0
		883.0		1,037.2		954.6
Operating income		**43.4**		82.3		85.2
Earnings	$	**23.8**	$	54.5	$	52.2

2015 compared to 2014 Construction services earnings decreased $30.7 million (56 percent) due to:

- Lower earnings of $25.1 million (after tax) largely due to lower workloads and margins in the Western region resulting from substantial completion of significant projects in 2014, lower equipment sales and rental margins, lower margins in the Central region and lower electrical supply sales and margins
- The absence of the favorable resolution of certain income tax matters and higher income tax benefits in 2014

These decreases were partially offset by lower selling, general and administrative expense of $3.0 million (after tax), largely related to lower payroll and benefit-related costs.

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
- 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.

Refining

Years ended December 31,		2015		2014		2013
				(Dollars in millions)		
Operating revenues	$	**178.3**	$	—	$	—
Operating expenses:						
Cost of crude oil		**159.8**		—		—
Operation and maintenance		**69.2**		7.6		.8
Depreciation, depletion and amortization		**16.5**		.9		—
Taxes, other than income		**1.7**		.6		—
		247.2		9.1		.8
Operating loss		**(68.9)**		(9.1)		(.8)
Loss attributable to the Company	$	**(22.5)**	$	(2.1)	$	(.1)
Refined product sales (MBbls)						
Diesel fuel		**1,072**		—		—
Naphtha		**996**		—		—
ATBs and other		**884**		—		—
Total refined product sales		**2,952**		—		—

The earnings variances discussed are the Company's proportionate share while the table includes the noncontrolling interest's portion of operating revenues, operating expenses, operating loss and refined product sales.

2015 compared to 2014 Refining recognized a loss of $22.5 million compared to a loss of $2.1 million in the prior year due to:

- Higher operation and maintenance expense, which includes $19.1 million (after tax) largely related to higher rail-related costs and higher contract services due to the commencement of operations
- Higher depreciation, depletion and amortization expense, which includes $4.8 million (after tax) due to Dakota Prairie Refinery being placed in service in 2015
- Higher interest expense, which includes $1.2 million (after tax) largely the result of lower capitalized interest and higher average debt

These decreases were partially offset by refined product sales gross margins which have been negatively impacted by market conditions.

2014 compared to 2013 Refining recognized a loss of $2.1 million compared to a loss of $100,000 in the prior year due to:

- Higher operation and maintenance expense, which includes $2.4 million (after tax) largely related to higher payroll and benefit-related costs
- Higher depreciation, depletion and amortization expense, which includes $300,000 (after tax) due to closeouts of certain in-service components

These decreases were partially offset by favorable income tax benefits.

Other

Years ended December 31,	2015	2014	2013
		(In millions)	
Operating revenues	$ **9.2**	$ 9.4	$ 9.6
Operating expenses:			
Operation and maintenance	**12.7**	11.0	11.6
Depreciation, depletion and amortization	**2.1**	2.2	2.1
Taxes, other than income	**.1**	.2	.1
	14.9	13.4	13.8
Operating loss	**(5.7)**	(4.0)	(4.2)
Loss	$ **(12.4)**	$ (7.2)	$ (10.6)

Included in Other are general and administrative costs and interest expense previously allocated to Fidelity that do not meet the criteria for income (loss) from discontinued operations.

2015 compared to 2014 Other loss increased $5.2 million compared to the prior year primarily due to the absence of prior year income tax benefits; higher operation and maintenance expense, largely a corporate asset impairment; as well as a foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

2014 compared to 2013 Other loss decreased $3.4 million compared to the prior year primarily due to favorable income tax changes, including the resolution of certain tax matters and higher income tax benefits.

Discontinued Operations

Years ended December 31,	2015	2014	2013
		(In millions)	
Income (loss) from discontinued operations before intercompany eliminations, net of tax	$ **(774.7)**	$ 114.6	$ 109.9
Intercompany eliminations	**2.3**	.5	—
Income (loss) from discontinued operations, net of tax	$ **(772.4)**	$ 115.1	$ 109.9

2015 compared to 2014 Discontinued operations recognized a loss of $772.4 million compared to income of $115.1 million in the prior year due to:

- Fair value impairments of the Company's assets held for sale of $475.4 million (after tax), as discussed in Item 8 - Note 2
- A noncash write-down of oil and gas properties of $315.3 million (after tax), as discussed in Item 8 - Note 2
- Lower average realized oil prices of 51 percent, excluding gain/loss on commodity derivatives

- Decreased oil production of 33 percent, primarily related to the divestment of certain properties in the last half of 2014, deferral of oil drilling activity due to the current low-price environment and the divestment of certain properties in 2015
- Lower average realized natural gas prices of 56 percent, excluding gain/loss on commodity derivatives
- Lower average realized NGL prices of 55 percent, excluding gain/loss on commodity derivatives

Partially offsetting these decreases were:

- Lower depreciation, depletion and amortization expense of $89.6 million (after tax), due to lower depletion rates and volumes and depreciation, depletion and amortization no longer being recorded on assets held for sale
- Lower lease operating expense of $24.0 million (after tax), largely the result of lower cost structures, as well as decreased production

2014 compared to 2013 Discontinued operations experienced an increase in income of $5.2 million compared to the prior year 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 $6.9 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

The following table represents key statistics of Fidelity's operations:

Years ended December 31,	**2015**	2014	2013
Production:			
Oil (MBbls)	**3,286**	4,919	4,815
NGL (MBbls)	**393**	609	781
Natural gas (MMcf)	**16,747**	20,822	28,008
Total production (MBOE)	**6,471**	8,998	10,264
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):			
Oil (per Bbl)	**$ 41.17**	$ 83.33	$ 89.70
NGL (per Bbl)	**$ 16.14**	$ 36.06	$ 37.39
Natural gas (per Mcf)	**$ 1.76**	$ 4.02	$ 2.89
Average realized prices (including realized gain/loss on commodity derivatives):			
Oil (per Bbl)	**$ 48.58**	$ 85.96	$ 89.35
NGL (per Bbl)	**$ 16.14**	$ 36.06	$ 37.39
Natural gas (per Mcf)	**$ 2.22**	$ 3.81	$ 2.96
Production costs, including taxes, per BOE:			
Lease operating costs	**$ 7.76**	$ 9.80	$ 8.01
Gathering and transportation	**1.59**	1.38	1.50
Production and property taxes	**2.41**	5.12	4.54
	$ 11.76	$ 16.30	$ 14.05

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,	2015	2014	2013
		(In millions)	
Intersegment transactions:			
Operating revenues	$ **80.9**	$ 136.6	$ 95.1
Purchased natural gas sold	**50.1**	44.8	39.3
Operation and maintenance	**27.8**	81.9	48.7
Depreciation, depletion and amortization	**.5**	—	—
Income from continuing operations	**1.5**	6.2	4.3

For more information on intersegment eliminations, see Item 8 - Note 13.

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 continually seeks opportunities to expand through organic growth opportunities and strategic acquisitions.
- The Company focuses on creating value through vertical integration among its business units.

Electric and natural gas distribution

- Organic growth opportunities are expected to result in substantial growth of the rate base, which at December 31, 2015, was $1.8 billion. Rate base growth is projected to be approximately 7 percent compounded annually over the next five years, including plans for an approximate $1.5 billion capital investment program.
- Investments of approximately $55 million were made in 2015 to serve growth in the electric and natural gas customer base associated with the Bakken oil development. Although customer growth was less than peak levels, the Company still saw strong growth in 2015. Due to sustained lower commodity prices, investments of approximately $35 million are expected in 2016.
- 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 $205 million, including development costs and substation upgrade costs. The project has been approved as a MISO multi-value project. More than 90 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.
- The Company is reviewing potential future generation options and is considering a large-scale resource. The integrated resource plan filed in July 2015 includes a 200 MW resource addition in the 2020 timeframe. The Company will continue to refine forecasted projections and adjust the timing of the addition if necessary.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system.
- The Company also is focused on growth through potential mergers and acquisitions.
- The Company is evaluating the final Clean Power Plan rule published by the EPA in October 2015, which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. It is unknown at this time what each state will require for emissions limits or reductions from each of the Company's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 6, 2018. On February 9, 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought. The Company has not included estimates for capital expenditures in 2016 through 2018 for the potential compliance requirements of the Clean Power Plan.
- Regulatory actions

  Completed Cases:

  - Since January 1, 2015, the Company has implemented a total of $28.5 million in final rates and $20.8 million in interim rates. This includes electric rate proceedings in North Dakota, South Dakota and before the FERC, and natural gas proceedings in Minnesota, Montana, North Dakota, Oregon, South Dakota and Wyoming.

Pending Cases:

- The Company is requesting a total of $59.7 million, including implemented interim rates, in rate relief from pending cases.
- On June 25, 2015, the Company filed an application with the MTPSC for an electric rate increase, as discussed in Item 8 - Note 16. The MTPSC has nine months in which to render a decision on the application.
- On June 30, 2015, the Company filed applications with the SDPUC for electric and natural gas rate increases, as discussed in Item 8 - Note 16. The SDPUC has six months in which to render a decision on the application for an electric rate increase.
- On September 30, 2015 and December 1, 2015, the Company filed applications with the MNPUC and WUTC, respectively, for natural gas rate increases, as discussed in Item 8 - Note 16.
- On October 21, 2015, the Company filed an application with the NDPSC for an update to the generation resource recovery rider and requested a renewable resource cost adjustment rider. On October 26, 2015, the Company resubmitted the application as two applications. The applications are discussed in Item 8 - Note 16.
- On November 25, 2015, the Company filed an application with the NDPSC for an update of its transmission cost adjustment for recovery of MISO-related charges and two transmission projects located in North Dakota, as discussed in Item 8 - Note 16.

Expected Filings:

- The Company expects to file electric rate cases in North Dakota and Wyoming in 2016 as well as natural gas rate cases in Idaho and Oregon.

Pipeline and midstream

- The Company has signed agreements to complete two expansion projects, the North Badlands expansion and the Northwest North Dakota expansion. The North Badlands project includes a 4-mile loop of the Garden Creek II pipeline and measurement and associated facilities, expected to be in service in fall of 2016. The Northwest North Dakota project includes modification of existing compression, a new unit and re-cylindering, expected to be in service the summer of 2016.
- The Company has 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. Project costs are estimated to be $50 million to $60 million. The project has been delayed by the plant owner.
- The Company is evaluating expansion into basins beyond its northern Rockies base.
- The Company is focused on improving existing operations and accelerating growth to become the leading pipeline company and midstream provider in all areas in which it operates.

Construction materials and contracting

- Approximate work backlog at December 31, 2015, was $491 million, compared to $438 million a year ago. Private work represents 8 percent of construction backlog and public work represents 92 percent of backlog. The Company recently announced the signing of its largest contract in its history, a $63.4 million highway construction project in Iowa, which is not included in the December 31, 2015, backlog amount.
- Projected revenues are in the range of $1.85 billion to $1.95 billion in 2016.
- The Company anticipates margins in 2016 to be slightly higher compared to 2015 margins.
- In December 2015 Congress passed, and the president signed, a $305 billion five-year highway bill for funding of transportation infrastructure projects that are a key part of the Company's market.
- 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 1.0 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Approximate work backlog at December 31, 2015, was $493 million, compared to $305 million a year ago. The backlog includes transmission, distribution, substation, industrial, petrochemical, mission critical, solar energy renewables, research and development, higher education, government, transportation, health care, hospitality, gaming, commercial, institutional and service work.
- Projected revenues are in the range of $950 million to $1.1 billion in 2016.
- The Company anticipates margins in 2016 to be slightly higher compared to 2015 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.

- As the eighth-largest specialty contractor, the Company continues to pursue opportunities for expansion and execute initiatives in current and new markets that align with the Company's expertise, resources and strategic growth plan.

Refining

- Dakota Prairie Refinery processes Bakken crude oil into diesel, which is marketed within the Bakken region. Other by-products, naphtha and ATBs, are transported to other areas. The production slate includes approximately 7,000 - 8,000 BPD of diesel, 5,500 - 6,500 BPD of naphtha and 4,500 - 5,500 BPD of ATBs. Work continues to increase the daily oil processing capacity of the plant.
- Company crude oil purchases for the intake have been at a discount to West Texas Intermediate. However, this discount, or differential, has been much narrower than anticipated because of market conditions in the Bakken.
- Diesel is sold locally at the refinery rack and Dakota Prairie Refinery posts a daily price based on market conditions. Dakota Prairie Refinery's posted diesel prices were in the $40 to $75 per barrel range, with an average $58.65 per barrel, during fourth quarter 2015.
- Naphtha is being railed into Canada to be used as a diluent for tar sands production and is tied to C5 pricing differentials to West Texas Intermediate. Naphtha prices ranged from $35 to $45 per barrel in the fourth quarter of 2015.

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 assets held for sale, long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; 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; and the valuation of stock-based compensation. 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 are 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, and timing of operations. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Prior to the oil and natural gas properties being classified as held for sale, changes in proved reserve quantities impacted the Company's depreciation, depletion and amortization expense since the Company used the units-of-production method to amortize its oil and natural gas properties. Historically, the proved reserves were used as the basis for the disclosures in Item 8 - Supplementary Financial Information and were the underlying basis of the "ceiling test" for the Company's oil and natural gas properties while those properties were classified as held for use.

Historically, the Company used the full-cost method of accounting for its exploration and production activities. Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were subject to a "ceiling test" that limited 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 were determined based on SEC Defined Prices and excluded cash flows associated with asset retirement obligations that had been accrued on the balance sheet. Judgments and assumptions were made when estimating and valuing proved reserves.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. The assets and liabilities were classified as held for sale and evaluated for impairment based on estimated fair value less cost to sell, as discussed later under Impairment testing of assets held for sale.

Impairment testing of assets held for sale

The Company evaluates disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management's views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, the majority of which closed during the fourth quarter of 2015, including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement had not been entered into, which the Company is continuing to market, the fair value was determined based on the market approach utilizing multiples based on similar interests in oil and natural gas properties, as the Company believes this was the most relevant measure of fair value for these assets. In the fourth quarter of 2015, the fair value assessment was determined using the market approach based on purchase and sale agreements, one of which has been signed and one of which the Company is currently negotiating.

Unforeseen events and changes in circumstances and market conditions and material differences in the value of the assets held for sale due to changes in estimates of future cash flows could negatively affect the estimated fair value of Fidelity and result in additional impairment charges. Various factors, including oil and natural gas prices, market differentials and changes in estimates of reserve quantities could result in future impairments of the Company's assets held for sale.

There is risk involved when determining the fair value of assets, 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 assets 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 its assets held for sale are reasonable based on the information that is known when the estimates are made.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding assets held for sale and 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 13. 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, 2015, 2014, and 2013, there were no significant impairment losses recorded. At December 31, 2015, 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 2015. 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 2015.

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 health care 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 health care 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 $1.3 million (after tax) for the year ended December 31, 2015.

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 health care 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 14.

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 $1.9 million for the year ended December 31, 2015.

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.

Significant federal tax credit carryforwards and federal and state net operating loss carryforwards have been generated. The Company may not be able to utilize all of these carryforwards prior to their expiration. As a result, the Company has recorded valuation allowances for the amounts it may not be able to utilize. Changes in tax regulations or assumptions regarding current and future taxable income could require a change to the estimated valuation allowances in the future resulting in a material impact to the Company's financial position and results of operations. For more information related to federal and state net operating loss carryforwards, see Item 8 - Notes 2 and 12.

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, 2015, the Company had cash and cash equivalents of $84.6 million and available capacity of $799.2 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.

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. Changes in cash flows for discontinued operations are related to the exploration and production business.

Cash flows provided by operating activities in 2015 increased $37.5 million from 2014. The increase was primarily due to lower working capital requirements of $205.7 million, primarily at the natural gas distribution business, largely related to lower natural gas sales and the construction services business, largely due to lower workloads; as well as lower income tax payments. Partially offsetting this increase was lower earnings primarily due to lower commodity prices at the exploration and production business.

Cash flows provided by operating activities in 2014 decreased $150.6 million from 2013. The decrease was primarily due to higher working capital requirements of $106.5 million, primarily at the construction services business. Cash flows from discontinued operations were lower largely due to higher working capital requirements at the exploration and production business.

Investing activities Cash flows used in investing activities in 2015 decreased $521.7 million from 2014 primarily due to lower capital expenditures and higher proceeds from the sale of properties, largely at the exploration and production business.

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

Financing activities Cash flows used in financing activities was $255.7 million in 2015 compared to cash flows provided by financing activities of $325.2 million in 2014. The change was primarily due to the lower issuance of long-term debt of $260.2 million, higher repayment of long-term debt of $201.2 million and lower issuance of common stock.

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 $55.5 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.

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, 2015, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $110.3 million. Pretax pension expense reflected in the years ended December 31, 2015, 2014 and 2013, was $2.0 million, $1.1 million and $3.0 million, respectively. The Company's pension expense is currently projected to be approximately $2.5 million to $3.5 million in 2016. Funding for the pension plans is actuarially determined. The minimum required contributions for 2015, 2014 and 2013 were approximately $3.9 million, $10.8 million and $13.2 million, respectively. For more information on the Company's pension plans, see Item 8 - Note 14.

Capital expenditures

The Company's capital expenditures for 2013 through 2015 and as anticipated for 2016 through 2018 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated (a)		
	2013	2014	**2015**	2016	2017	2018
			(In millions)			
Capital expenditures:						
Electric	$ 169	$ 185	**$ 333**	$ 122	$ 196	$ 202
Natural gas distribution	101	121	**131**	145	164	135
Pipeline and midstream	40	62	**18**	27	73	94
Construction materials and contracting	35	38	**48**	35	99	76
Construction services	15	27	**38**	9	12	13
Refining (b)	87	115	**22**	3	4	3
Other	2	2	**4**	4	3	2
Net proceeds from sale or disposition of property and other (c)	(29)	(60)	**(64)**	(3)	(5)	(6)
Net capital expenditures before discontinued operations	420	490	**530**	342	546	519
Discontinued operations (c)	308	354	**(203)** (d)	—	—	—
Net capital expenditures	728	844	**327**	342	546	519
Retirement of long-term debt	424	369	**569**	244	51	175
	$ 1,152	$ 1,213	**$ 896**	$ 586	$ 597	$ 694

(a) 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.
(b) Reflects the Company's proportionate share of Dakota Prairie Refinery.
(c) Proceeds from the sale of the exploration and production assets are excluded from capital expenditure projections.
(d) Capital expenditures from discontinued operations includes gross proceeds of $316.6 million from the sale of the exploration and production assets, which does not include purchase price adjustments and income tax benefits.

Capital expenditures for 2015, 2014 and 2013 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 $(40.5) million in 2015, $(88.8) million in 2014 and $(70.0) million in 2013.

The 2015 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 2016 through 2018 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
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- 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 2016 through 2018 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, 2015. 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 7.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2015:

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		$ 44.5	(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)	$ 47.9		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 650.0		$ 18.0	(b)	$ 39.4		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement		$ 75.0		$ 45.5		$ 18.3	(d)	6/30/16

(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) Outstanding letter(s) of credit reduce 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.

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. 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 2.5 times and 3.1 times for the 12 months ended December 31, 2015 and 2014, respectively.

Total equity as a percent of total capitalization was 57 percent and 61 percent at December 31, 2015 and 2014, respectively. 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, in accordance with the terms and conditions of the agreement. Proceeds from the shares of common stock under the agreement have been used for corporate development purposes and other general corporate purposes. Under the agreement, the Company did not issue any shares of stock between January 1, 2015 and December 31, 2015. Since inception of the Equity Distribution Agreement, the Company issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through December 31, 2015.

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. 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, 2015, which reduced capacity under this uncommitted private shelf agreement.

Dakota Prairie Refining, LLC On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016. The credit agreement is used to meet the operational needs of the facility.

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.

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 7 and 17. At December 31, 2015, the Company's commitments under these obligations were as follows:

	2016	2017	2018	2019	2020	Thereafter	Total
				(In millions)			
Long-term debt	$ 243.8	$ 51.0	$ 175.2	$ 119.7	$ 21.0	$ 1,260.5	$ 1,871.2
Estimated interest payments*	80.1	70.9	69.3	61.3	58.9	527.8	868.3
Operating leases	52.3	42.7	35.5	26.4	15.9	76.9	249.7
Purchase commitments	443.7	228.0	138.9	112.9	90.4	853.9	1,867.8
	$ 819.9	$ 392.6	$ 418.9	$ 320.3	$ 186.2	$ 2,719.1	$ 4,857.0

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

At December 31, 2015, the Company had total liabilities of $242.2 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $4.5 million at December 31, 2015, 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 8.

The Company has no uncertain tax positions and no minimum funding requirements for its defined benefit pension plans for 2016.

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 14.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2015, 2014 or 2013.

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 from time to time 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 5.

Commodity price risk

Fidelity historically utilized 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.

There were no derivative agreements at December 31, 2015. The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2014. These agreements called 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

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, 2015 and 2014, 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, 2015.

	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 238.5	$ 43.5	$ 108.6	$ 51.2	$ 15.0	$ 1,235.0	$ 1,691.8	$ 1,715.5
Weighted average interest rate	6.4%	6.3%	6.1%	4.3%	5.2%	4.9%	5.2%	—
Variable rate	$ 5.3	$ 7.5	$ 66.6	$ 68.5	$ 6.0	$ 25.5	$ 179.4	$ 177.9
Weighted average interest rate	1.8%	2.1%	1.8%	.9%	2.2%	2.5%	1.6%	—

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, 2015. 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, 2015.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ David L. Goodin	/s/ Doran N. Schwartz
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, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, 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 19, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 19, 2016

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, 2015, 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, 2015, 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, 2015 of the Company and our report dated February 19, 2016 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 19, 2016

Consolidated Statements of Income

Years ended December 31,	2015	2014	2013
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	$ 1,148,272	$ 1,246,646	$ 1,156,838
Nonregulated pipeline and midstream, construction materials and contracting, construction services, refining and other	3,043,277	2,868,170	2,763,333
Total operating revenues	4,191,549	4,114,816	3,920,171
Operating expenses:			
Fuel and purchased power	86,238	89,312	83,528
Purchased natural gas sold	450,114	558,463	495,471
Cost of crude oil	159,811	—	—
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	277,638	269,225	253,214
Nonregulated pipeline and midstream, construction materials and contracting, construction services, refining and other	2,593,300	2,529,020	2,426,145
Depreciation, depletion and amortization	227,730	203,980	200,398
Taxes, other than income	142,585	145,393	140,713
Total operating expenses	3,937,416	3,795,393	3,599,469
Operating income	254,133	319,423	320,702
Other income	19,232	9,873	6,086
Interest expense	93,068	86,906	83,803
Income before income taxes	180,297	242,390	242,985
Income taxes	65,603	63,227	74,294
Income from continuing operations	114,694	179,163	168,691
Income (loss) from discontinued operations, net of tax (Note 2)	(772,385)	115,175	109,879
Net income (loss)	(657,691)	294,338	278,570
Net loss attributable to noncontrolling interest	(35,256)	(3,895)	(363)
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$ (623,120)	$ 297,548	$ 278,248
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	$ .77	$ .95	$ .89
Discontinued operations, net of tax	(3.97)	.60	.58
Earnings (loss) per common share - basic	$ (3.20)	$ 1.55	$ 1.47
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	$ .77	$ .95	$ .89
Discontinued operations, net of tax	(3.97)	.60	.58
Earnings (loss) per common share - diluted	$ (3.20)	$ 1.55	$ 1.47
Weighted average common shares outstanding - basic	194,928	192,507	188,855
Weighted average common shares outstanding - diluted	194,986	192,587	189,693

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2015	2014	2013
		(In thousands)	
Net income (loss)	**$ (657,691)**	$ 294,338	$ 278,570
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized loss on derivative instruments arising during the period, net of tax of \$0, \$0 and \$(3,116) in 2015, 2014 and 2013, respectively	**—**	—	(5,594)
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of \$233, \$240 and \$339 in 2015, 2014 and 2013, respectively	**404**	399	727
Reclassification adjustment for (gain) loss on derivative instruments included in income (loss) from discontinued operations, net of tax of \$0, \$173 and \$(2,887) in 2015, 2014 and 2013, respectively	**—**	295	(4,916)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**404**	694	(9,783)
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of \$(55), \$(7,665) and \$11,818 in 2015, 2014 and 2013, respectively	**(88)**	(12,409)	18,539
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of \$1,128, \$492 and \$1,276 in 2015, 2014 and 2013, respectively	**1,794**	796	2,001
Reclassification of postretirement liability adjustment to regulatory asset, net of tax of \$1,416, \$4,509 and \$0 in 2015, 2014 and 2013, respectively	**2,255**	7,202	—
Postretirement liability adjustment	**3,961**	(4,411)	20,540
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of \$(105), \$(99) and \$(177) in 2015, 2014 and 2013, respectively	**(173)**	(162)	(299)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of \$490, \$0 and \$70 in 2015, 2014 and 2013, respectively	**802**	—	143
Foreign currency translation adjustment	**629**	(162)	(156)
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of \$(91), \$(83) and \$(105) in 2015, 2014 and 2013, respectively	**(170)**	(154)	(194)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of \$70, \$73 and \$59 in 2015, 2014 and 2013, respectively	**131**	135	109
Net unrealized loss on available-for-sale investments	**(39)**	(19)	(85)
Other comprehensive income (loss)	**4,955**	(3,898)	10,516
Comprehensive income (loss)	**(652,736)**	290,440	289,086
Comprehensive loss attributable to noncontrolling interest	**(35,256)**	(3,895)	(363)
Comprehensive income (loss) attributable to common stockholders	**$ (617,480)**	$ 294,335	$ 289,449

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

Consolidated Balance Sheets

December 31,	2015	2014
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 84,591	$ 81,855
Receivables, net	590,105	599,186
Inventories	253,727	289,410
Deferred income taxes	32,849	32,012
Prepayments and other current assets	35,189	83,763
Current assets held for sale	24,581	131,177
Total current assets	1,021,042	1,217,403
Investments	119,704	117,883
Property, plant and equipment (Note 1)	6,817,668	6,294,778
Less accumulated depreciation, depletion and amortization	2,506,571	2,386,113
Net property, plant and equipment	4,311,097	3,908,665
Deferred charges and other assets:		
Goodwill (Note 3)	635,204	635,204
Other intangible assets, net (Note 3)	7,342	9,840
Other	366,485	322,943
Noncurrent assets held for sale	166,734	1,620,470
Total deferred charges and other assets	1,175,765	2,588,457
Total assets	$ 6,627,608	$ 7,832,408
Liabilities and Equity		
Current liabilities:		
Short-term borrowings (Note 7)	$ 45,500	$ —
Long-term debt due within one year	243,789	268,552
Accounts payable	310,466	279,115
Taxes payable	45,775	39,955
Dividends payable	36,784	35,607
Accrued compensation	46,130	57,402
Other accrued liabilities	171,592	155,765
Current liabilities held for sale	47,603	154,728
Total current liabilities	947,639	991,124
Long-term debt (Note 7)	1,627,443	1,825,278
Deferred credits and other liabilities:		
Deferred income taxes	720,319	714,022
Other liabilities	811,659	756,759
Noncurrent liabilities held for sale	—	295,441
Total deferred credits and other liabilities	1,531,978	1,766,222
Commitments and contingencies (Notes 14, 16 and 17)		
Equity:		
Preferred stocks (Note 9)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 10) Authorized - 500,000,000 shares, $1.00 par value Issued - 195,804,665 shares in 2015 and 194,754,812 shares in 2014	195,805	194,755
Other paid-in capital	1,230,119	1,207,188
Retained earnings	996,355	1,762,827
Accumulated other comprehensive loss	(37,148)	(42,103)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,381,505	3,119,041
Total stockholders' equity	2,396,505	3,134,041
Noncontrolling interest	124,043	115,743
Total equity	2,520,548	3,249,784
Total liabilities and equity	$ 6,627,608	$ 7,832,408

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

Consolidated Statements of Equity

Years ended December 31, 2015, 2014 and 2013

	Preferred Stock		Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock		Noncontrolling Interest	Total
	Shares	Amount	Shares	Amount				Shares	Amount		
					(In thousands, except shares)						
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
Net loss	—	—	—	—	—	(622,435)	—	—	—	(35,256)	(657,691)
Other comprehensive income	—	—	—	—	—	—	4,955	—	—	—	4,955
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(143,352)	—	—	—	—	(143,352)
Stock-based compensation	—	—	—	—	3,689	—	—	—	—	—	3,689
Net tax deficit on stock-based compensation	—	—	—	—	(1,606)	—	—	—	—	—	(1,606)
Issuance of common stock	—	—	1,049,853	1,050	20,848	—	—	—	—	—	21,898
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	52,000	52,000
Distribution to noncontrolling interest	—	—	—	—	—	—	—	—	—	(8,444)	(8,444)
Balance at December 31, 2015	**150,000**	**$ 15,000**	**195,804,665**	**$ 195,805**	**$ 1,230,119**	**$ 996,355**	**$ (37,148)**	**(538,921)**	**$ (3,626)**	**$124,043**	**$ 2,520,548**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2015	2014	2013
		(In thousands)	
Operating activities:			
Net income (loss)	$ **(657,691)**	$ 294,338	$ 278,570
Income (loss) from discontinued operations, net of tax	**(772,385)**	115,175	109,879
Income from continuing operations	**114,694**	179,163	168,691
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**227,730**	203,980	200,398
Deferred income taxes	**301**	58,990	28,551
Excess tax benefit on stock-based compensation	**—**	(4,729)	—
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(313)**	4,010	(25,635)
Inventories	**(17,100)**	(22,795)	28,292
Other current assets	**50,097**	(40,617)	(13,569)
Accounts payable	**49,117**	(42,138)	26,285
Other current liabilities	**6,325**	(15,988)	(26,360)
Other noncurrent changes	**10,256**	(21,450)	(30,786)
Net cash provided by continuing operations	**441,107**	298,426	355,867
Net cash provided by discontinued operations	**200,037**	305,241	398,441
Net cash provided by operating activities	**641,144**	603,667	754,308
Investing activities:			
Capital expenditures	**(625,375)**	(608,028)	(531,332)
Acquisitions, net of cash acquired	**—**	(269)	—
Net proceeds from sale or disposition of property and other	**54,569**	29,598	40,802
Investments	**1,515**	(1,041)	302
Proceeds from sale of equity method investments	**—**	—	1,896
Net cash used in continuing operations	**(569,291)**	(579,740)	(488,332)
Net cash provided by (used in) discontinued operations	**186,838**	(324,451)	(294,329)
Net cash used in investing activities	**(382,453)**	(904,191)	(782,661)
Financing activities:			
Issuance of short-term borrowings	**45,500**	—	9,500
Repayment of short-term borrowings	**—**	(11,500)	—
Issuance of long-term debt	**345,920**	606,084	507,924
Repayment of long-term debt	**(569,498)**	(368,249)	(423,707)
Proceeds from issuance of common stock	**21,898**	150,060	14,554
Dividends paid	**(142,835)**	(136,712)	(98,405)
Excess tax benefit on stock-based compensation	**—**	4,729	—
Tax withholding on stock-based compensation	**—**	(5,564)	—
Contribution from noncontrolling interest	**52,000**	86,900	27,000
Distribution to noncontrolling interest	**(8,444)**	—	—
Net cash provided by (used in) continuing operations	**(255,459)**	325,748	36,866
Net cash used in discontinued operations	**(271)**	(554)	—
Net cash provided by (used in) financing activities	**(255,730)**	325,194	36,866
Effect of exchange rate changes on cash and cash equivalents	**(225)**	(155)	(215)
Increase in cash and cash equivalents	**2,736**	24,515	8,298
Cash and cash equivalents - beginning of year	**81,855**	57,340	49,042
Cash and cash equivalents - end of year	$ **84,591**	$ 81,855	$ 57,340

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 midstream, construction materials and contracting, construction services, refining and other. The electric and natural gas distribution businesses, as well as a portion of the pipeline and midstream business, are regulated. Construction materials and contracting, construction services, refining and the other businesses, as well as a portion of the pipeline and midstream business, are nonregulated. For further descriptions of the Company's businesses, see Note 13. 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 4 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, 2015, up to the date of issuance of these consolidated financial statements.

In the second quarter of 2015, the Company announced its plan to market Fidelity, previously referred to as the Company's exploration and production segment, and exit that line of business. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations. In addition, the assets and liabilities have been treated and classified as held for sale. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on discontinued operations, see Note 2.

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 $27.8 million and $29.4 million at December 31, 2015 and 2014, 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, 2015 and 2014, was $9.8 million and $9.5 million, respectively.

Inventories and natural gas in storage

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. Crude oil and refined products at Dakota Prairie Refinery are carried at lower of cost or market value using the last-in, first-out method. In 2015, Dakota Prairie Refinery recorded $12.2 million (before tax) of inventory impairments due to the lower of cost or market valuation which is reflected in cost of crude oil on the Consolidated Statements of Income. All other inventories are stated at the lower of average cost or market value. 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:

	2015	2014
	(In thousands)	
Aggregates held for resale	**$ 115,854**	$ 108,161
Asphalt oil	**36,498**	42,135
Materials and supplies	**16,997**	54,282
Merchandise for resale	**15,318**	24,420
Refined products	**8,498**	—
Natural gas in storage (current)	**21,023**	19,302
Crude oil	**4,678**	5,045
Other	**34,861**	36,065
Total	**$ 253,727**	$ 289,410

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 $49.1 million and $49.3 million at December 31, 2015 and 2014, respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. 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 6 and 14.

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. In addition, the Company capitalizes interest, when applicable, 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:

	2015	2014	2013
		(In thousands)	
Interest capitalized	**$ 4,902**	$ 8,586	$ 6,033
AFUDC - borrowed	**$ 4,907**	$ 3,022	$ 2,767
AFUDC - equity	**$ 7,971**	$ 5,803	$ 3,322

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. 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:

	2015	2014	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 1,003,173	$ 627,952	39
Distribution	375,612	343,692	44
Transmission	255,842	229,997	57
Construction in progress	42,436	150,445	-
Other	109,085	105,015	14
Natural gas distribution:			
Distribution	1,624,645	1,481,390	35
Construction in progress	20,530	59,310	-
Other	431,406	364,059	22
Pipeline and midstream:			
Transmission	460,305	449,276	53
Gathering	37,831	39,595	20
Storage	44,011	43,994	60
Construction in progress	7,549	5,386	-
Other	40,168	39,910	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	158,949	227,598	16
Construction in progress	89	691	-
Other	9,827	11,938	10
Construction materials and contracting:			
Land	123,723	125,372	-
Buildings and improvements	69,011	70,566	19
Machinery, vehicles and equipment	937,084	921,564	12
Construction in progress	18,615	8,709	-
Aggregate reserves	404,995	403,731	*
Construction services:			
Land	6,460	5,265	-
Buildings and improvements	23,824	17,936	25
Machinery, vehicles and equipment	121,940	112,973	6
Other	11,055	8,221	3
Refining:			
Refinery	445,198	88,232	20
Construction in progress	135	313,613	-
Other:			
Land	2,837	2,837	-
Other	46,700	48,100	23
Eliminations	(15,367)	(12,589)	
Less accumulated depreciation, depletion and amortization	2,506,571	2,386,113	
Net property, plant and equipment	$ 4,311,097	$ 3,908,665	

* 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, oil and natural gas properties, and assets held for sale, 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 the third quarter of 2015, the Company recognized an impairment of $14.1 million (before tax) related to the sale of certain non-strategic natural gas gathering assets that were written down to their estimated fair value that was determined using the market approach. In the second quarters of 2015 and 2013, the Company recognized impairments of $3.0 million (before tax) and $14.5 million (before tax), respectively, related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a continued 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 their estimated fair value that was determined using the income approach. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income. For more information on these nonrecurring fair value measurements, see Note 6.

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 13. 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, 2015, 2014 and 2013, there were no significant impairment losses recorded. At December 31, 2015, 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 2015. 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.

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 $102.1 million and $99.7 million at December 31, 2015 and 2014, 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:

		2015		2014
		(In thousands)		
Costs and estimated earnings in excess of billings on uncompleted contracts	**$**	**64,369**	$	58,243
Billings in excess of costs and estimated earnings on uncompleted contracts	**$**	**68,048**	$	47,011

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

		2015		2014
		(In thousands)		
Short-term retainage*	**$**	**46,207**	$	47,551
Long-term retainage**		**1,605**		1,053
Total retainage	**$**	**47,812**	$	48,604

* 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 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 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 5.

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 8.

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 which are filed annually. Natural gas costs refundable through rate adjustments were $20.9 million and $13.2 million at December 31, 2015 and 2014, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $547,000 and $19.6 million at December 31, 2015 and 2014, 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.

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 (loss) per common share were computed by dividing earnings (loss) 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 2015, 2014 and 2013, there were no shares excluded from the calculation of diluted earnings per share. 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:

	2015	2014	2013
		(In thousands)	
Weighted average common shares outstanding - basic	**194,928**	192,507	188,855
Effect of dilutive performance share awards	**58**	80	838
Weighted average common shares outstanding - diluted	**194,986**	192,587	189,693
Shares excluded from the calculation of diluted earnings per share	**—**	—	—

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 assets held for sale, long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; 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; and the valuation of stock-based compensation. 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:

		2015		2014		2013
				(In thousands)		
Interest, net of amount capitalized and AFUDC - borrowed of $9,809, $11,608 and $8,800 in 2015, 2014 and 2013, respectively	**$**	**90,386**	$	81,241	$	81,575
Income taxes paid, net	**$**	**33,409**	$	64,211	$	52,580

Noncash investing transactions at December 31 were as follows:

		2015		2014		2013
				(In thousands)		
Property, plant and equipment additions in accounts payable	**$**	**51,702**	$	62,453	$	22,832

New accounting standards

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity In April 2014, the FASB issued guidance related to the definition and reporting of discontinued operations. The guidance changed the definition of discontinued operations to include only disposals of a component or group of components that represent a strategic shift and that have a major effect on an entity's operations or financial results. The guidance also expands the disclosure requirements for transactions that meet the definition of a discontinued operation, and also requires entities to disclose information about individually significant components that are disposed of or held for sale that do not meet the definition of a discontinued operation. This guidance was effective for the Company on January 1, 2015, and is to be applied prospectively. The adoption required additional disclosures for the Company's discontinued operations, however it did not impact the Company's results of operations, financial position or cash flows.

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 was to be effective for the Company on January 1, 2017. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance one year and allowing entities to early adopt. With this decision, the guidance will be effective for the Company on January 1, 2018. 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.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance was effective for the Company on January 1, 2016, and is to be applied retrospectively. Early adoption of this guidance was permitted, however the Company has not elected to do so. The guidance will require a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but will not impact the Company's results of operations or cash flows.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance was effective for the Company on January 1, 2016, with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures, however it will not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with IFRS. This guidance will be effective for the Company on January 1, 2017, and should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position and cash flows.

Balance Sheet Classification of Deferred Taxes In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. The guidance will require all deferred tax assets and liabilities to be classified as noncurrent. These amendments will align GAAP with IFRS. This guidance will be effective for the Company on January 1, 2017, with early adoption permitted. Entities will have the option to apply the guidance prospectively, for all deferred tax assets and liabilities, or retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its financial position and disclosures, however it will not impact the Company's results of operations or cash flows.

Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance will be effective for the Company on January 1, 2018, with early adoption of certain amendments permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

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 5.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2015, 2014 and 2013, 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, 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)
Other comprehensive income (loss) before reclassifications	—	(88)	(173)	(170)	(431)
Amounts reclassified from accumulated other comprehensive loss	404	1,794	802	131	3,131
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	—	2,255	—	—	2,255
Net current-period other comprehensive income (loss)	404	3,961	629	(39)	4,955
Balance at December 31, 2015	**$ (2,667)**	**$ (34,257)**	**$ (200)**	**$ (24)**	**$ (37,148)**

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

	2015	2014	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Interest rate derivative instruments	**$ (637)**	$ (639)	Interest expense
	233	240	Income taxes
	(404)	(399)	
Commodity derivative instruments, net of tax	**—**	(295)	Income (loss) from discontinued operations, net of tax
	(404)	(694)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**(2,922)**	(1,288)	(a)
	1,128	492	Income taxes
	(1,794)	(796)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss)	**(1,292)**	—	Other income
	490	—	Income taxes
	(802)	—	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	**(201)**	(208)	Other income
	70	73	Income taxes
	(131)	(135)	
Total reclassifications	**$ (3,131)**	$ (1,625)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 14.

Note 2 - Discontinued Operations

In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The completion of the majority of these sales occurred in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. The sale of Fidelity is part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value. The assets and liabilities for these operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2015	2014
	(In thousands)	
Assets		
Current assets:		
Receivables, net	**$ 13,387**	$ 94,132
Inventories	**1,308**	11,401
Commodity derivative instruments	**—**	18,335
Prepayments and other current assets	**9,886**	7,309
Total current assets held for sale	**24,581**	131,177
Noncurrent assets:		
Investments	**37**	37
Net property, plant and equipment	**793,422**	1,618,099
Deferred income taxes	**127,655**	—
Other	**161**	2,334
Less allowance for impairment of assets held for sale	**754,541**	—
Total noncurrent assets held for sale	**166,734**	1,620,470
Total assets held for sale	**$ 191,315**	$ 1,751,647
Liabilities		
Current liabilities:		
Long-term debt due within one year	**$ —**	$ 897
Accounts payable	**25,013**	103,556
Taxes payable	**1,052**	19,900
Deferred income taxes	**3,620**	8,206
Accrued compensation	**13,080**	5,373
Other accrued liabilities	**4,838**	16,796
Total current liabilities held for sale	**47,603**	154,728
Noncurrent liabilities:		
Deferred income taxes	**—**	238,391
Other liabilities	**—**	57,050
Total noncurrent liabilities held for sale	**—**	295,441
Total liabilities held for sale	**$ 47,603**	$ 450,169

At December 31, 2015, the Company’s deferred tax assets included in assets held for sale were largely comprised of $78.9 million of federal and state net operating loss carryforwards and $38.1 million of basis differences on oil and natural gas producing properties. At December 31, 2014, the Company’s deferred tax liabilities included in liabilities held for sale were largely comprised of $270.0 million of basis differences on oil and natural gas producing properties offset in part by $26.4 million of asset retirement obligations.

The Company had federal income tax net operating loss carryforwards of $208.2 million at December 31, 2015, and no federal income tax net operating loss carryforwards at December 31, 2014. At December 31, 2015 and 2014, the Company had various state income tax net operating loss carryforwards of $201.4 million and $5.9 million, respectively. The federal net operating loss carryforwards expire in 2036 if not utilized. The state net operating loss carryforwards are due to expire between 2016 and 2036. It is likely a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances of $300,000 and $253,000 have been provided in 2015 and 2014, respectively.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management's views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity's assets at June 30, 2015, and recording an impairment of $400.0 million ($252.0 million after tax) during the second quarter of 2015. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, the majority of which closed during the fourth quarter of 2015, including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement has not been entered into, which the Company is continuing to market, the fair value was determined based on the market approach utilizing multiples based on similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the current carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity's assets at September 30, 2015, and recording an impairment of $356.1 million ($224.4 million after tax). In the fourth quarter of 2015, the fair value assessment was determined using the market approach based on purchase and sale agreements, one of which has been signed and one of which the Company is currently negotiating. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.6 million ($1.0 million after tax) in the fourth quarter of 2015. The impairments were included in operating expenses from discontinued operations. The estimated fair value of Fidelity's assets have been categorized as Level 3 in the fair value hierarchy.

At December 31, 2015, the Company has accrued liabilities of approximately $2.5 million for estimated transaction costs which will result in future cash expenditures. In addition to the estimated transaction costs, and due in part to the change in plans to sell the assets of Fidelity rather than sell Fidelity as a company, Fidelity incurred and expensed approximately $4.9 million of exit and disposal costs in 2015 and expects to incur an additional $6.1 million of exit and disposal costs in 2016. The exit and disposal costs are associated with severance and other related matters, excluding the office lease expenses discussed in the following paragraph. The majority of these exit and disposal activities are expected to be completed by the end of the second quarter of 2016.

Fidelity is vacating its office space in Denver, Colorado. An amendment of lease has been executed with payments of $4.2 million required under the lease in 2016. A termination payment of $3.3 million was made during the fourth quarter of 2015 and existing office furniture and fixtures will be relinquished to the lessor in 2016.

Unforeseen events and changes in circumstances and market conditions and material differences in the value of the assets held for sale due to changes in estimates of future cash flows could negatively affect the estimated fair value of Fidelity and result in additional impairment charges. Various factors, including oil and natural gas prices, market differentials and changes in estimates of reserve quantities could result in future impairments of the Company's assets held for sale.

Historically, the Company used 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.

Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were 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.

The Company's capitalized cost under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2015. SEC Defined Prices, adjusted for market differentials, were used to calculate the ceiling test. Accordingly, the Company was required to write down its oil and natural gas producing properties. The Company recorded a $500.4 million ($315.3 million after tax) noncash write-down in operating expenses from discontinued operations in the first quarter of 2015.

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 which is reflected in discontinued operations. 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.

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. The Company incurred legal expenses and had a benefit related to the resolution of this matter in the second quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes.

The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations to the after-tax net income (loss) from discontinued operations of the Company's Consolidated Statements of Income at December 31 were as follows:

	2015	2014	2013
		(In thousands)	
Operating revenues	**$ 184,853**	$ 547,571	$ 536,023
Operating expenses	**1,423,037**	378,891	364,120
Operating income (loss)	**(1,238,184)**	168,680	171,903
Other income	**2,374**	1,163	549
Interest expense	**235**	110	114
Income (loss) from discontinued operations before income taxes	**(1,236,045)**	169,733	172,338
Income taxes	**(463,660)**	54,558	62,459
Income (loss) from discontinued operations	**$ (772,385)**	$ 115,175	$ 109,879

Note 3 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2015, were as follows:

	Balance at January 1, 2015 *	Goodwill Acquired During the Year	Balance at December 31, 2015 *
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Pipeline and midstream	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,441	—	103,441
Total	$ 635,204	$ —	$ 635,204

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

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 midstream	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 midstream segment, which occurred in prior periods.

Other amortizable intangible assets at December 31 were as follows:

	2015	2014
	(In thousands)	
Customer relationships	$ 20,975	$ 21,310
Accumulated amortization	(16,845)	(15,556)
	4,130	5,754
Noncompete agreements	4,409	5,080
Accumulated amortization	(3,655)	(4,098)
	754	982
Other	8,304	10,921
Accumulated amortization	(5,846)	(7,817)
	2,458	3,104
Total	$ 7,342	$ 9,840

Amortization expense for amortizable intangible assets for the years ended December 31, 2015, 2014 and 2013, was $2.5 million, $3.2 million and $4.0 million, respectively. Estimated amortization expense for intangible assets is $2.2 million in 2016, $1.9 million in 2017, $1.0 million in 2018, $900,000 in 2019, $300,000 in 2020 and $1.0 million thereafter.

Note 4 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2015	2014
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 185,832	$ 182,565
Taxes recoverable from customers (a)	Over plant lives	27,682	22,910
Manufactured gas plant sites remediation (a)	Up to 2 years	18,617	17,548
Plant costs (a)	Up to 1 year	8,000	4,551
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	547	19,575
Long-term debt refinancing costs (a)	Up to 22 years	7,031	7,864
Costs related to identifying generation development (a)	Up to 11 years	3,808	4,165
Other (a) (b)	Largely within 1- 4 years	11,741	10,408
Total regulatory assets		263,258	269,586
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		182,981	338,641
Taxes refundable to customers (c)		17,060	17,772
Natural gas costs refundable through rate adjustments (d)		20,884	13,238
Other (c) (d)		22,193	16,601
Total regulatory liabilities		243,118	386,252
Net regulatory position		$ 20,140	$ (116,666)

* 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, 2015 and 2014, approximately $224.7 million and $229.6 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 5 - 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. The Company had no derivative instruments at December 31, 2015, and as of December 31, 2014, credit risk was not material.

Fidelity

At December 31, 2014, Fidelity held oil swap agreements with total forward notional volumes of 270,000 Bbl and natural gas swap agreements with total forward notional volumes of 5.0 million MMBtu. At December 31, 2015, Fidelity had no outstanding derivative agreements. Fidelity historically utilized 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. The gains and losses on the commodity derivative instruments held by Fidelity were included in income (loss) from discontinued operations and the associated assets and liabilities were classified as held for sale.

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 income (loss) from discontinued operations on the Consolidated Statements of Income at the date the oil and natural gas quantities were settled.

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, 2015, 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:

	2015	2014	2013
		(In thousands)	
Commodity derivatives designated as cash flow hedges:			
Amount of loss recognized in accumulated other comprehensive loss (effective portion), net of tax	**$ —**	$ —	$ (6,153)
Amount of (gain) loss reclassified from accumulated other comprehensive loss into discontinued operations (effective portion), net of tax	**—**	295	(4,916)
Amount of loss recognized in operating revenues (ineffective portion), before tax	**—**	—	(1,422)
Interest rate derivatives designated as cash flow hedges:			
Amount of gain recognized in accumulated other comprehensive loss (effective portion), net of tax	**—**	—	559
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	**404**	399	727
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 discontinued operations, before tax	**(18,335)**	23,400	(4,845)

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 gross amount 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
		(In thousands)
Not designated as hedges:		
Commodity derivatives	Current assets held for sale	$ 18,335
Total asset derivatives		$ 18,335

All of the Company's commodity derivative instruments at December 31, 2014, 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 (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

Note 6 - 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 $67.5 million and $65.8 million as of December 31, 2015 and 2014, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2015, 2014 and 2013, were $1.7 million, $3.4 million and $13.5 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, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 9,128	$ 19	$ (49)	$ 9,098
U.S. Treasury securities	1,315	—	(6)	1,309
Total	$ 10,443	$ 19	$ (55)	$ 10,407

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

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 are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using 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. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to these funds.

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 RIN obligations are based on the market approach using quoted prices from an independent pricing service. RINs are assigned to biofuels produced or imported into the United States as required by the EPA, which sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the United States. As a producer of diesel fuel, Dakota Prairie Refinery is required to blend biofuels into the fuel it produces at a rate that will meet the EPA's quota. RINs are purchased in the open market to satisfy the requirement as Dakota Prairie Refinery is currently unable to blend biofuels into the diesel fuel it produces.

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, 2015 and 2014, 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, 2015, 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, 2015
	(In thousands)			
Assets:				
Money market funds	$ —	$ 1,420	$ —	$ 1,420
Insurance contract*	—	67,459	—	67,459
Available-for-sale securities:				
Mortgage-backed securities	—	9,098	—	9,098
U.S. Treasury securities	—	1,309	—	1,309
Total assets measured at fair value	$ —	$ 79,286	$ —	$ 79,286
Liabilities:				
RIN obligations	$ —	$ 3,052	$ —	$ 3,052
Total liabilities measured at fair value	$ —	$ 3,052	$ —	$ 3,052

* The insurance contract invests approximately 9 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 19 percent in common stock of large-cap companies, 63 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.

	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	$ —	$ 890	$ —	$ 890
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
Total assets measured at fair value	$ —	$ 76,912	$ —	$ 76,912

* 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.

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, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

During the second quarters of 2015 and 2013, natural gas gathering assets at the pipeline and midstream segment 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, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $1.1 million.

During the third quarter of 2015, the Company was negotiating the sale of certain non-strategic natural gas gathering assets at the pipeline and midstream segment and as a result these assets were found to be impaired and were written down to their estimated fair value using the market approach. The estimated fair value of natural gas gathering assets that were impaired at September 30, 2015, was largely determined by agreed upon pricing in a purchase and sale agreement that the Company was negotiating, and these assets were sold in the fourth quarter of 2015. At September 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $10.8 million.

The fair value of these natural gas gathering assets have been categorized as Level 3 in the fair value hierarchy.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. For more information on this Level 3 nonrecurring fair value measurement, see Note 2.

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:

	2015		2014	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,871,232**	**$ 1,893,442**	$ 2,093,830	$ 2,238,548

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

Note 7 - 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, 2015	Amount Outstanding at December 31, 2014	Letters of Credit at December 31, 2015	Expiration Date
					(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0	$ 44.5 (b)	$ 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)	$ 47.9	$ 21.0	$ —	7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 650.0	$ 18.0 (b)	$ 211.0 (b)	$ 39.4	5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement		$ 75.0	$ 45.5	$ —	$ 18.3 (d)	6/30/16

(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) Outstanding letter(s) of credit reduce 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.

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 September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016.

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. 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.

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. 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.

In December 2015, the lenders under the revolving credit agreement and master shelf agreement provided a waiver and an amendment, respectively, to certain covenants under these agreements removing any potential restrictions related to the disposition of the Fidelity assets.

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.

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, 2015, 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:

	2015	2014
	(In thousands)	
Senior Notes at a weighted average rate of 5.18%, due on dates ranging from February 1, 2016 to January 15, 2055	**$ 1,616,246**	$ 1,636,662
Commercial paper at a weighted average rate of .73%, supported by revolving credit agreements	**62,500**	288,500
Term Loan Agreements at a weighted average rate of 2.16%, due on dates ranging from April 22, 2018 to April 22, 2023	**69,000**	72,000
Medium-Term Notes at a weighted average rate of 6.68%, due on dates ranging from September 1, 2020 to March 16, 2029	**50,000**	35,000
Other notes at a weighted average rate of 5.25%, due on February 1, 2035	**24,589**	39,662
Credit agreements at a weighted average rate of 1.82%, due on dates ranging from July 14, 2018 to November 30, 2038	**48,906**	22,042
Discount	**(9)**	(36)
Total long-term debt	**1,871,232**	2,093,830
Less current maturities	**243,789**	268,552
Net long-term debt	**$ 1,627,443**	$ 1,825,278

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2015, aggregate $243.8 million in 2016; $51.0 million in 2017; $175.2 million in 2018; $119.7 million in 2019; $21.0 million in 2020 and $1,260.5 million thereafter.

Note 8 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, 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:

	2015	2014
	(In thousands)	
Balance at beginning of year	**$ 27,211**	$ 27,327
Liabilities incurred	**2,751**	1,697
Liabilities settled	**(1,708)**	(3,231)
Accretion expense	**1,163**	1,112
Revisions in estimates	**211,836**	(73)
Other	**971**	379
Balance at end of year	**$ 242,224**	$ 27,211

The 2015 revisions in estimates consist principally of updated natural gas distribution mains and lines asset retirement obligation costs.

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.

Note 9 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2015	2014
	(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 2015, 2014 and 2013, 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 10 - Common Stock

For the years 2015, 2014 and 2013, dividends declared on common stock were $.7350, $.7150 and $.6950 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 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2013 through December 2013, and September 2015 through December 2015, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2015, there were 13.9 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 $1.6 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2015. 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 $322 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, 2015. 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 11 - 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, 2015, there are 5.6 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy employee performance share awards and purchases shares on the open market for nonemployee director stock awards.

Total stock-based compensation expense (after tax) was $2.9 million, $4.4 million and $3.9 million in 2015, 2014 and 2013, respectively.

As of December 31, 2015, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.6 million (before income taxes) which will be amortized over a weighted average period of 1.5 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 58,181 shares with a fair value of $1.1 million, 43,088 shares with a fair value of $1.1 million and 36,713 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2015, 2014 and 2013, respectively.

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, 2015, were as follows:

Grant Date	Performance Period	Target Grant of Shares
March 2013	2013-2015	188,388
February 2014	2014-2016	142,989
February 2015	2015-2017	220,078
June 2015	2015-2017	14,441

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 2015, 2014 and 2013 were:

	2015	2014	2013
Weighted average grant-date fair value	**$18.98**	$41.13	$29.01
Blended volatility range	**22.86% – 24.61%**	18.94% – 20.43%	16.10% – 19.39%
Risk-free interest rate range	**.05% – 1.07%**	.03% – .74%	.09% – .40%
Weighted average discounted dividends per share	**$1.57**	$2.15	$2.12

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 2015 and 2013.

A summary of the status of the performance share awards for the year ended December 31, 2015, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	688,455	$ 28.16
Granted	258,454	18.98
Vested	—	—
Forfeited	(381,013)	22.31
Nonvested at end of period	565,896	$ 27.90

Note 12 - Income Taxes

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

	2015	2014	2013
		(In thousands)	
United States	**$ 181,623**	$ 242,442	$ 242,569
Foreign	**(1,326)**	(52)	416
Income before income taxes from continuing operations	**$ 180,297**	$ 242,390	$ 242,985

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

	2015	2014	2013
		(In thousands)	
Current:			
Federal	$ 59,483	$ 4,403	$ 41,624
State	5,789	(166)	4,148
Foreign	30	—	(29)
	65,302	4,237	45,743
Deferred:			
Income taxes:			
Federal	3,199	55,514	29,616
State	(2,478)	2,467	(859)
Investment tax credit - net	(420)	1,009	(206)
	301	58,990	28,551
Total income tax expense	$ 65,603	$ 63,227	$ 74,294

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

	2015	2014
	(In thousands)	
Deferred tax assets:		
Postretirement	$ 97,666	$ 99,853
Compensation-related	33,844	35,669
Alternative minimum tax credit carryforward	28,173	23,678
Customer advances	12,623	12,245
Asset retirement obligations	8,694	7,894
Legal and environmental contingencies	6,377	7,890
Other	58,202	52,862
Total deferred tax assets	245,579	240,091
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	791,368	773,160
Postretirement	71,835	70,642
Intangible asset amortization	23,950	22,810
Other	36,906	46,637
Total deferred tax liabilities	924,059	913,249
Valuation allowance	8,990	8,852
Net deferred income tax liability	$ (687,470)	$ (682,010)

As of December 31, 2015 and 2014, the Company had various state income tax net operating loss carryforwards of $116.2 million and $114.3 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $10.9 million and $7.5 million, respectively. The federal income tax credit carryforwards expire in 2036 if not utilized and state income tax credit carryforwards are due to expire between 2016 and 2032. It is likely that a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances have been provided. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future. The alternative minimum tax credit carryforwards do not expire. For information regarding net operating loss carryforwards and valuation allowances related to discontinued operations, see Note 2.

The following table reconciles the change in the net deferred income tax liability from December 31, 2014, to December 31, 2015, to deferred income tax expense:

	2015
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 5,460
Deferred taxes associated with other comprehensive income	(3,086)
Other	(2,073)
Deferred income tax expense for the period	$ 301

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,		2015		2014			2013		
		Amount	**%**		Amount	%		Amount	%
				(Dollars in thousands)					
Computed tax at federal statutory rate	**$**	**63,104**	**35.0**	$	84,836	35.0	$	85,045	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax		**4,903**	**2.7**		7,048	2.9		7,379	3.0
Noncontrolling interest		**12,340**	**6.8**		1,363	.5		—	—
Federal renewable energy credit		**(3,400)**	**(1.9)**		(3,655)	(1.5)		(3,404)	(1.4)
Tax compliance and uncertain tax positions		**(194)**	**(.1)**		(8,987)	(3.7)		(3,902)	(1.6)
Domestic production activities		**—**	**—**		(3,993)	(1.6)		(666)	(.3)
Other		**(11,150)**	**(6.1)**		(13,385)	(5.5)		(10,158)	(4.1)
Total income tax expense	**$**	**65,603**	**36.4**	$	63,227	26.1	$	74,294	30.6

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 $2.4 million at December 31, 2015. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2015, was approximately $900,000.

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 or non-U.S. income tax examinations by tax authorities for years ending prior to 2011. With few exceptions, as of December 31, 2015, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2010.

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

		2015		2014		2013
				(In thousands)		
Balance at beginning of year	**$**	**105**	$	7,845	$	7,845
Settlements		**—**		(7,740)		—
Lapse of statute of limitations		**(105)**		—		—
Balance at end of year	**$**	**—**	$	105	$	7,845

At December 31, 2015 and 2014, there were no 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 $119,000, including approximately $14,000 for the payment of interest and penalties at December 31, 2014. Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2015, 2014 and 2013, the Company recognized approximately $122,000, $387,000 and $107,000, respectively, of interest expense in income tax expense.

For the years ended December 31, 2015, 2014 and 2013, the Company recognized approximately $3.4 million, $1.2 million and $914,000, respectively, in interest expense. Penalties were not material in 2015, 2014 and 2013. The Company recognized interest income of approximately $3.7 million, $469,000 and $655,000 for the years ended December 31, 2015, 2014 and 2013, respectively. At December 31, 2015 and 2014, the Company had accrued liabilities of approximately $94,000 and interest receivable of $367,000, respectively, for the payment or receipt of interest.

Note 13 - 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 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 midstream 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.

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 provides utility construction services specializing in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies.

The refining segment refines crude oil and produces and sells diesel fuel, naphtha, ATBs and other by-products of the production process. The refining segment includes Dakota Prairie Refinery which is jointly owned by WBI Energy and Calumet and is located in southwestern North Dakota, along with WBI Energy's other activity that supports the refinery.

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 includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in the Brazilian Transmission Lines.

Discontinued operations includes the results of Fidelity other than certain general and administrative costs and interest expense as described above. Fidelity engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The completion of the majority of these sales occurred in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. Discontinued operations also includes legal expenses and a benefit related to the vacation of an arbitration award in 2014 related to Centennial Resources. For more information on discontinued operations, see Note 2.

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:

	2015	2014	2013
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	**$ 280,615**	$ 277,874	$ 257,260
Natural gas distribution	**817,419**	921,986	851,945
Pipeline and midstream	**50,238**	46,786	47,633
	1,148,272	1,246,646	1,156,838
Nonregulated operations:			
Pipeline and midstream	**54,282**	64,494	56,427
Construction materials and contracting	**1,901,530**	1,740,089	1,675,444
Construction services	**907,767**	1,062,055	1,029,909
Refining	**178,262**	—	—
Other	**1,436**	1,532	1,553
	3,043,277	2,868,170	2,763,333
Total external operating revenues	**$ 4,191,549**	$ 4,114,816	$ 3,920,171
Intersegment operating revenues:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and midstream	**51,716**	46,085	40,511
Construction materials and contracting	**2,752**	25,241	36,693
Construction services	**18,660**	57,474	9,930
Refining	**—**	—	—
Other	**7,755**	7,832	8,067
Intersegment eliminations	**(80,883)**	(136,632)	(95,201)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 37,583**	$ 35,008	$ 32,789
Natural gas distribution	**64,756**	54,700	50,031
Pipeline and midstream	**27,981**	29,749	29,105
Construction materials and contracting	**65,937**	68,557	74,470
Construction services	**13,420**	12,874	11,939
Refining	**16,463**	896	14
Other	**2,070**	2,196	2,050
Intersegment eliminations	**(480)**	—	—
Total depreciation, depletion and amortization	**$ 227,730**	$ 203,980	$ 200,398
Interest expense:			
Electric	**$ 17,421**	$ 15,595	$ 12,590
Natural gas distribution	**29,471**	27,217	25,123
Pipeline and midstream	**9,895**	9,946	10,148
Construction materials and contracting	**15,183**	16,368	17,394
Construction services	**3,959**	4,176	4,306
Refining	**3,450**	119	182
Other	**14,292**	13,739	14,216
Intersegment eliminations	**(603)**	(254)	(156)
Total interest expense	**$ 93,068**	$ 86,906	$ 83,803

	2015	2014	2013
		(In thousands)	
Income taxes:			
Electric	**$ 11,523**	$ 12,442	$ 9,683
Natural gas distribution	**11,377**	11,350	16,633
Pipeline and midstream	**7,505**	12,232	3,466
Construction materials and contracting	**41,619**	18,586	24,765
Construction services	**16,432**	24,753	29,504
Refining	**(13,815)**	(2,533)	(76)
Other	**(8,107)**	(9,798)	(6,812)
Intersegment eliminations	**(931)**	(3,805)	(2,869)
Total income taxes	**$ 65,603**	$ 63,227	$ 74,294
Earnings (loss) on common stock:			
Regulated operations:			
Electric	**$ 35,914**	$ 36,731	$ 34,837
Natural gas distribution	**23,607**	30,484	37,656
Pipeline and midstream	**20,680**	15,440	15,388
	80,201	82,655	87,881
Nonregulated operations:			
Pipeline and midstream	**(7,430)**	9,226	(7,687)
Construction materials and contracting	**89,096**	51,510	50,946
Construction services	**23,762**	54,432	52,213
Refining	**(22,457)**	(2,038)	(72)
Other	**(12,376)**	(7,317)	(10,605)
	70,595	105,813	84,795
Intersegment eliminations	**(1,531)**	(6,095)	(4,307)
Earnings on common stock before income (loss) from discontinued operations	**149,265**	182,373	168,369
Income (loss) from discontinued operations, net of tax	**(772,385)**	115,175	109,879
Total earnings (loss) on common stock	**$ (623,120)**	$ 297,548	$ 278,248
Capital expenditures:			
Electric	**$ 332,876**	$ 185,121	$ 168,557
Natural gas distribution	**130,793**	120,613	101,279
Pipeline and midstream	**18,315**	61,754	40,533
Construction materials and contracting	**48,126**	37,896	34,607
Construction services	**38,269**	26,942	15,102
Refining	**22,052**	115,655	86,559
Other	**3,755**	2,131	2,249
Net proceeds from sale or disposition of property and other	**(63,831)**	(60,177)	(28,392)
Total net capital expenditures	**$ 530,355**	$ 489,935	$ 420,494
Assets:			
Electric*	**$ 1,327,258**	$ 1,030,611	$ 884,283
Natural gas distribution*	**2,042,925**	1,931,908	1,786,068
Pipeline and midstream	**593,025**	655,735	620,639
Construction materials and contracting	**1,279,057**	1,272,231	1,305,808
Construction services	**450,896**	454,602	450,614
Refining	**464,699**	429,102	178,062
Other**	**278,433**	306,572	236,543
Assets held for sale	**191,315**	1,751,647	1,611,430
Total assets	**$ 6,627,608**	$ 7,832,408	$ 7,073,447

	2015	2014	2013
		(In thousands)	
Property, plant and equipment:			
Electric*	**$ 1,786,148**	$ 1,457,101	$ 1,315,822
Natural gas distribution*	**2,076,581**	1,904,759	1,776,901
Pipeline and midstream	**758,729**	818,388	789,569
Construction materials and contracting	**1,553,428**	1,529,942	1,510,355
Construction services	**163,279**	144,395	134,948
Refining	**445,333**	401,845	172,603
Other	**49,537**	50,937	49,997
Eliminations	**(15,367)**	(12,589)	(4,473)
Less accumulated depreciation, depletion and amortization	**2,506,571**	2,386,113	2,284,169
Net property, plant and equipment	**$ 4,311,097**	$ 3,908,665	$ 3,461,553

* 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).

Capital expenditures for 2015, 2014 and 2013 include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. The net transactions were $(40.5) million in 2015, $(88.8) million in 2014 and $(70.0) million in 2013.

Note 14 - 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.

Prior to 2013, defined pension plan benefits and accruals for all nonunion and certain union plans were frozen. On June 30, 2015, an additional union plan was frozen. At December 31, 2015, all of the Company's defined pension plans have been 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, 2015 and 2014, and amounts recognized in the Consolidated Balance Sheets at December 31, 2015 and 2014, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	**2015**	2014
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 475,337**	$ 402,772	**$ 99,012**	$ 81,726
Service cost	**86**	129	**1,816**	1,518
Interest cost	**17,141**	17,682	**3,607**	3,521
Plan participants' contributions	**—**	—	**1,408**	1,399
Actuarial (gain) loss	**(24,875)**	80,520	**(5,873)**	18,024
Benefits paid	**(24,729)**	(25,766)	**(7,236)**	(7,176)
Benefit obligation at end of year	**442,960**	475,337	**92,734**	99,012
Change in net plan assets:				
Fair value of plan assets at beginning of year	**354,363**	334,844	**87,586**	84,543
Actual gain (loss) on plan assets	**(10,879)**	24,500	**258**	7,527
Employer contribution	**13,912**	20,785	**577**	1,293
Plan participants' contributions	**—**	—	**1,408**	1,399
Benefits paid	**(24,729)**	(25,766)	**(7,236)**	(7,176)
Fair value of net plan assets at end of year	**332,667**	354,363	**82,593**	87,586
Funded status - under	**$ (110,293)**	$ (120,974)	**$ (10,141)**	$ (11,426)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ —**	$ —	**$ 5,095**	$ 4,345
Other accrued liabilities (current)	**—**	—	**(421)**	(322)
Other liabilities (noncurrent)	**(110,293)**	(120,974)	**(14,815)**	(15,449)
Net amount recognized	**$ (110,293)**	$ (120,974)	**$ (10,141)**	$ (11,426)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 208,671**	$ 207,430	**$ 22,484**	$ 25,779
Prior service cost (credit)	**—**	294	**(14,374)**	(15,744)
Total	**$ 208,671**	$ 207,724	**$ 8,110**	$ 10,035

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 4.

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 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.

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:

	2015	2014
	(In thousands)	
Projected benefit obligation	**$ 442,960**	$ 475,337
Accumulated benefit obligation	**$ 442,960**	$ 475,337
Fair value of plan assets	**$ 332,667**	$ 354,363

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

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	**2015**	2014	2013
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	**$ 86**	$ 129	$ 155	**$ 1,816**	$ 1,518	$ 1,675
Interest cost	**17,141**	17,682	16,249	**3,607**	3,521	3,215
Expected return on assets	**(22,254)**	(21,218)	(19,917)	**(4,795)**	(4,617)	(4,343)
Amortization of prior service cost (credit)	**36**	71	71	**(1,371)**	(1,393)	(1,457)
Recognized net actuarial loss	**7,016**	4,869	7,173	**1,960**	649	1,814
Curtailment loss	**258**	—	—	**—**	—	—
Net periodic benefit cost (credit), including amount capitalized	**2,283**	1,533	3,731	**1,217**	(322)	904
Less amount capitalized	**316**	388	727	**120**	(21)	164
Net periodic benefit cost (credit)	**1,967**	1,145	3,004	**1,097**	(301)	740
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**8,257**	77,238	(60,173)	**(1,336)**	15,114	(30,461)
Amortization of actuarial loss	**(7,016)**	(4,869)	(7,173)	**(1,960)**	(649)	(1,814)
Amortization of prior service (cost) credit	**(294)**	(71)	(71)	**1,371**	1,393	1,457
Total recognized in accumulated other comprehensive (income) loss	**947**	72,298	(67,417)	**(1,925)**	15,858	(30,818)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	**$ 2,914**	$ 73,443	$ (64,413)	**$ (828)**	$ 15,557	$ (30,078)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 is $6.2 million. 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 2016 are $1.5 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	
	2015	2014	**2015**	2014
Discount rate	**4.00%**	3.70%	**4.06%**	3.74%
Expected return on plan assets	**6.75%**	7.00%	**5.75%**	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	
	2015	2014	**2015**	2014
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%

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, 2015, 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 30 percent to 40 percent equity securities and 60 percent to 70 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:

	2015	2014
Health care trend rate assumed for next year	**4.0% – 8.0%**	4.0% – 7.0%
Health care cost trend rate - ultimate	**5.0% – 6.0%**	5.0% – 6.0%
Year in which ultimate trend rate achieved	**2021**	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, 2015:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 203	$ (169)
Effect on postretirement benefit obligation	$ 4,006	$ (3,407)

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, 2015 and 2014, 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, 2015, 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, 2015
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 8,379	$ —	$ 8,379
Equity securities:				
U.S. companies	15,135	—	—	15,135
International companies	2,332	—	—	2,332
Collective and mutual funds*	154,400	63,568	—	217,968
Corporate bonds	—	62,145	—	62,145
Municipal bonds	—	11,680	—	11,680
U.S. Government securities	5,288	6,823	—	12,111
Total assets measured at fair value	$ 177,155	$ 152,595	$ —	$ 329,750

* Collective and mutual funds invest approximately 19 percent in common stock of large-cap U.S. companies, 6 percent in common stock of mid-cap U.S. companies, 16 percent in corporate bonds, 29 percent in common stock of international companies, 16 percent in cash equivalents and 14 percent in other investments.

	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.

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, 2015 and 2014, 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, 2015, 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, 2015
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 3,261	$ —	$ 3,261
Equity securities:				
U.S. companies	2,274	—	—	2,274
International companies	9	—	—	9
Insurance contract*	—	77,044	—	77,044
Total assets measured at fair value	$ 2,283	$ 80,305	$ —	$ 82,588

* The insurance contract invests approximately 19 percent in common stock of large-cap U.S. companies, 22 percent in U.S. Government securities, 10 percent in mortgage-backed securities, 36 percent in corporate bonds and 13 percent in other investments.

	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.

The Company does not expect to contribute to its defined benefit pension plans and expects to contribute approximately $800,000 to its postretirement benefit plans in 2016.

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)	
2016	$ 24,223	$ 5,234	$ 197
2017	24,680	5,351	191
2018	24,980	5,420	183
2019	25,323	5,441	175
2020	25,700	5,331	168
2021 - 2025	133,029	27,261	688

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. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated upgrades. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was $7.1 million, $6.6 million and $7.3 million in 2015, 2014 and 2013, respectively. The total projected benefit obligation for these plans was $110.8 million and $115.6 million at December 31, 2015 and 2014, respectively. The accumulated benefit obligation for these plans was $104.6 million and $108.2 million at December 31, 2015 and 2014, respectively. A weighted average discount rate of 3.77 percent and 3.51 percent at December 31, 2015 and 2014, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent at December 31, 2015 and 2014, were used to determine benefit obligations. A discount rate of 3.51 percent and 4.32 percent for the years ended December 31, 2015 and 2014, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent for the years ended December 31, 2015 and 2014, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $6.5 million in 2016; $6.7 million in 2017; $7.1 million in 2018; $7.3 million in 2019; $7.8 million in 2020 and $37.7 million for the years 2021 through 2025.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2015, 2014 and 2013 were $207,000, $104,000 and $25,000, respectively.

The Company had investments of $105.2 million and $101.4 million at December 31, 2015 and 2014, respectively, consisting of equity securities of $54.2 million and $54.9 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $34.3 million and $32.8 million, respectively, and other investments of $16.7 million and $13.7 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 $36.8 million in 2015, $34.4 million in 2014 and $33.2 million in 2013.

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 2015 and 2014 is for the plan's year-end at December 31, 2014, and December 31, 2013, 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 2015	2014	FIP/RP Status Pending/ Implemented	Contributions 2015	2014	2013	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green as of 12/31/2015	Green as of 12/31/2014	No	**$ 5,517**	$ 9,061	$ 6,358	No	12/31/2017
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2015	Red as of 6/30/2014	Implemented	**2,252**	1,392	1,284	No	11/29/2015*
IBEW Local No. 246 Pension Plan	34-6582842-001	Yellow as of 5/31/2015	Yellow as of 5/31/2014	Implemented	**433**	694	1,848	No	10/31/2017
IBEW Local No. 357 Pension Plan A	88-6023284-001	Green	Green	No	**1,896**	3,575	2,348	No	5/31/2018
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2015	Red as of 2/28/2014	Implemented	**745**	1,110	1,489	No	9/2/2018
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2015	Green as of 5/31/2014	No	**1,169**	1,125	1,121	No	9/30/2016
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2015	Yellow as of 4/30/2014	Implemented	**937**	568	531	No	6/5/2016
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red as of 12/31/2015	Red as of 12/31/2014	Implemented	**677**	608	583	No	3/31/2016-7/31/2018
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**5,271**	6,476	5,883	No	6/30/2015*-11/30/2019
Pension Trust Fund for Operating Engineers	94-6090764-001	Red as of 12/31/2015	Red as of 12/31/2014	Implemented	**1,997**	1,445	1,510	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 12/31/2015	Red as of 12/31/2014	Implemented	**—**	68	76	No	10/31/2005*
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2015	Red as of 12/31/2014	Implemented	**714**	676	512	No	6/30/2016
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	**26**	31	42	No	1/31/2014*–1/31/2019
Other funds					**17,478**	15,988	15,675		
Total contributions					**$ 39,112**	$ 42,817	$ 39,260		

* 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	2014 and 2013
IBEW Local No. 82 Pension Plan	2014 and 2013
Local Union No. 124 IBEW Pension Trust Fund	2014 and 2013
Local Union 212 IBEW Pension Trust Fund	2014 and 2013
IBEW Local Union No. 357 Pension Plan A	2014 and 2013
IBEW Local 573 Pension Plan	2014
IBEW Local 648 Pension Plan	2014 and 2013
Idaho Plumbers and Pipefitters Pension Plan	2014
Minnesota Teamsters Construction Division Pension Fund	2014 and 2013
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming*	2014 and 2013
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2014 and 2013

* 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. The Company estimated the withdrawal liability to be approximately $14.0 million at December 31, 2014. In the first quarter of 2015, the Company accrued an additional withdrawal liability of approximately $2.4 million. The total withdrawal liability is currently estimated at $16.4 million. 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 $31.4 million, $34.6 million and $37.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Amounts contributed in 2015, 2014 and 2013 to defined contribution multiemployer plans were $19.5 million, $22.0 million and $20.6 million, respectively.

Note 15 - 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:

	2015	2014
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 157,761**	$ 64,283
Less accumulated depreciation	**48,242**	43,043
	$ 109,519	$ 21,240
Coyote Station:		
Utility plant in service	**$ 140,895**	$ 138,810
Less accumulated depreciation	**94,755**	94,443
	$ 46,140	$ 44,367
Wygen III:		
Utility plant in service	**$ 65,023**	$ 65,597
Less accumulated depreciation	**6,788**	5,928
	$ 58,235	$ 59,669

Note 16 - Regulatory Matters

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, as well as environmental remediation expenses. On November 2, 2015, Cascade, staff of the OPUC, the Citizens' Utility Board of Oregon and the Northwest Industrial Gas Users filed a settlement agreement that resolved all issues of the application and reflected a natural gas rate increase of approximately $600,000 annually or approximately .8 percent, to be effective February 1, 2016. The OPUC issued an order on December 28, 2015, accepting the settlement.

On June 25, 2015, Montana-Dakota filed an application for an electric rate increase with the MTPSC. Montana-Dakota requested a total increase of approximately $11.8 million annually or approximately 21.1 percent above current rates. The increase is necessary to recover Montana-Dakota’s investments in modifications to generation facilities to comply with new EPA requirements, the addition and/or replacement of capacity and energy requirements and transmission facilities along with the additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. Montana-Dakota requested an interim increase of approximately $11.0 million annually. The MTPSC denied the request for interim rates on December 15, 2015. On February 8, 2016, Montana-Dakota and the interveners to the case filed a stipulation and settlement agreement reflecting an annual increase of $3.0 million effective April 1, 2016, and an additional increase of $4.4 million effective April 1, 2017. A technical hearing was held February 9, 2016. This matter is pending before the MTPSC.

On June 30, 2015, Montana-Dakota filed an application with the SDPUC for an electric rate increase. Montana-Dakota requested a total increase of approximately $2.7 million annually or approximately 19.2 percent above current rates. The increase is necessary to recover Montana-Dakota's investments in modifications to generation facilities to comply with new EPA requirements, the addition and/or replacement of capacity and energy requirements and transmission facilities along with the additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. This matter is pending before the SDPUC. An interim increase of $2.7 million, subject to refund, was implemented January 1, 2016. A hearing is scheduled for the week of April 11, 2016.

On June 30, 2015, Montana-Dakota filed an application for a natural gas rate increase with the SDPUC. Montana-Dakota requested a total increase of approximately $1.5 million annually or approximately 3.1 percent above current rates. The increase is necessary to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes, partially offset by an increase in customers and throughput. This matter is pending before the SDPUC. An interim increase of $1.5 million, subject to refund, was implemented January 1, 2016. A hearing is scheduled for April 4, 2016.

On September 1, 2015, and as amended on October 5, 2015, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff including a revenue requirement for the Company's multivalue project of $3.8 million, which was effective January 1, 2016.

On September 30, 2015, Great Plains filed an application for a natural gas rate increase with the MNPUC. Great Plains requested a total increase of approximately $1.6 million annually or approximately 6.4 percent above current rates. The increase is necessary to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes. Great Plains requested an interim increase of $1.5 million or approximately 6.4 percent, subject to refund. The interim request was approved by the MNPUC on November 30, 2015, and was effective with service rendered on and after January 1, 2016. This matter is pending before the MNPUC. A technical hearing is scheduled for April 7 and 8, 2016.

On October 21, 2015, Montana-Dakota filed an application with the NDPSC for an update of an electric generation resource recovery rider and requested a renewable resource cost adjustment rider. Montana-Dakota requested a combined total of approximately $25.3 million with approximately $20.0 million incremental to current rates, to be effective January 1, 2016. This application was resubmitted as two applications on October 26, 2015.

On October 26, 2015, Montana-Dakota filed an application requesting a renewable resource cost adjustment rider of $15.4 million for the recovery of the Thunder Spirit Wind project, placed in service in the fourth quarter of 2015. A settlement was reached with the NDPSC Advocacy Staff whereby Montana-Dakota agreed to a 10.5 percent return on equity on the renewable resource cost adjustment rider, as well as committed to file an electric general rate case no later than September 30, 2016. The renewable resource cost adjustment rider was approved by the NDPSC on January 5, 2016, to be effective January 7, 2016, resulting in an annual increase of $15.1 million on an interim basis pending the determination of the return on equity in the upcoming rate case.

On October 26, 2015, Montana-Dakota filed an application for an update to the electric generation resource recovery rider, which currently includes recovery of Montana-Dakota's investment in the 88-MW simple-cycle natural gas turbine and associated facilities near Mandan, North Dakota. The application proposed to also include the 19 MW of new generation from natural gas-fired internal combustion engines and associated facilities, near Sidney, Montana, placed in service in the fourth quarter of 2015, for a total of $9.9 million or an incremental increase of $4.6 million to be recovered under the rider. On January 25, 2016, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement. If approved by the NDPSC, the settlement would result in an interim increase of $9.7 million or an incremental increase of $4.4 million, subject to refund, a 10.5 percent return on equity and Montana-Dakota would commit to filing an electric general rate case no later than September 30, 2016. A technical hearing on this matter was held on February 4, 2016.

On November 25, 2015, Montana-Dakota filed an application with the NDPSC for an update of its transmission cost adjustment for recovery of MISO-related charges and two transmission projects located in North Dakota, equating to $6.8 million to be collected under the transmission cost adjustment. An update to the transmission cost adjustment was submitted on January 19, 2016, to reflect the provisions of the settlement agreement approved by the NDPSC for the renewable resource cost adjustment rider. An informal hearing with the NDPSC was held January 20, 2016, regarding this matter. The NDPSC approved the filing on February 10, 2016, with rates to be effective February 12, 2016.

On December 1, 2015, Cascade filed an application with the WUTC for a natural gas rate increase. Cascade requested a total increase of approximately $10.5 million annually or approximately 4.2 percent above current rates. The requested increase includes costs associated with increased infrastructure investment and the associated operating expenses. The filing is pending before the WUTC. The natural gas rate increase is expected to be effective November 1, 2016. A hearing on this matter has been scheduled to begin August 2, 2016.

Note 17 - 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 $19.5 million and $27.6 million, which include liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2015 and 2014, respectively, including amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

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. 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. WBI Energy Midstream resolved this matter in December 2015 through a settlement that included dismissal of the litigation and payment of an amount that was not material.

In a related matter, Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging WBI Energy Midstream breached obligations to operate its gathering system as a common carrier under United States and Montana law. WBI Energy Midstream removed the action to the United States District Court for the District of Montana. The parties subsequently settled the breach of contract claim and, subject to final determination on liability, stipulated to the damages on the common carrier claim, for amounts that are not material. A trial on the common carrier claim was held during July 2013. On December 9, 2014, the United States District Court for the District of Montana issued an order determining WBI Energy Midstream breached its obligations as a common carrier and ordered judgment in favor of Omimex for the amount of the stipulated damages. WBI Energy Midstream filed an appeal from the United States District Court for the District of Montana's order and judgment.

Exploration and Production During the ordinary course of its business, Fidelity is subject to audit for various production related taxes by certain state and federal tax authorities for varying periods as well as claims for royalty obligations under lease agreements for oil and gas production. Disputes may exist regarding facts and questions of law relating to the tax and royalty obligations.

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 which JTL expects will be approved by the Montana DEQ in the first half of 2016. The Company intends to resolve the Montana First Judicial District Court litigation through settlement.

Construction Services Bombard Mechanical is a third-party defendant in litigation pending in Nevada State District Court in which the plaintiff claims damages attributable to defects in the construction of a 48 story residential tower built in 2008 for which Bombard Mechanical performed plumbing and mechanical work as a subcontractor. On March 12, 2015, the plaintiff presented cost of repair estimates totaling approximately $21 million for alleged plumbing and mechanical system defects associated in whole or in part with work performed by Bombard Mechanical. Bombard Mechanical is being defended in the action under a policy of insurance subject to a reservation of rights.

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Coos County The Oregon DEQ issued a Notice of Civil Penalty to LTM dated October 12, 2015, asserting violations of Oregon water quality statutes and rules resulting from the stockpiling and grading of earthen material during 2014 at a site in Coos County and assessing civil penalties totaling approximately $160,000. The Notice of Civil Penalty alleges violations by causing pollution to an intermittent creek, by conducting activity described in a general National Pollutant Discharge Elimination System permit without applying for coverage under the general permit, by placing the earthen materials in a location where they were likely to escape or be carried into waters of the state, and by failing to submit a revised ESCP where there was a change in the size of the project or the location of the disturbed area. The Notice of Civil Penalty also requires LTM to submit a revised ESCP containing measures to prevent further erosion from entering the intermittent creek and to file a work plan outlining how the earthen material will be permanently stabilized or removed. LTM intends to request a contested case hearing on the Notice of Civil Penalty.

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 DEQ released a ROD 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 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, December 1, 2014 and December 1, 2015.

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 $12.9 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. 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 4.

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, 2015, were $52.3 million in 2016, $42.7 million in 2017, $35.5 million in 2018, $26.4 million in 2019, $15.9 million in 2020 and $76.9 million thereafter. Rent expense was $65.1 million, $48.5 million and $39.7 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, and service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. These commitments range from one to 45 years. The commitments under these contracts as of December 31, 2015, were $443.7 million in 2016, $228.0 million in 2017, $138.9 million in 2018, $112.9 million in 2019, $90.4 million in 2020 and $853.9 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, 2015, 2014 and 2013, were $861.4 million, $925.2 million and $860.5 million, respectively.

Guarantees

In 2009, multiple sales agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, 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.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, insurance deductibles and loss limits, and certain other guarantees. At December 31, 2015, the fixed maximum amounts guaranteed under these agreements aggregated $128.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $33.1 million in 2016; $35.0 million in 2017; $600,000 in 2018; $54.9 million in 2019; $1.0 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2015. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2015, the fixed maximum amounts guaranteed under these letters of credit aggregated $57.3 million, all of which expire in 2016. The amount outstanding by subsidiaries of the Company under the above letters of credit was $4.1 million and was reflected on the Consolidated Balance Sheet at December 31, 2015. In the event of default under these letter of credit obligations, the subsidiary issuing the letter of credit for that particular obligation would be required to make payments under its letter of credit.

Centennial and WBI Holdings have guaranteed certain debt obligations of Dakota Prairie Refining. For more information, see Variable interest entities in this note.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2015.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2015, approximately $530.0 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

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. For more information, see Note 1.

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement are $150 million and $75 million, respectively. Capital commitments in excess of $300 million are being shared equally between WBI Energy and Calumet. WBI Energy's and Calumet's cumulative capital contributions, net of distributions, as of December 31, 2015, are $230.4 million and $163.6 million, respectively. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan. The net loss attributable to noncontrolling interest on the Consolidated Statements of Income is pretax as Dakota Prairie Refining is a limited liability company.

On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016. Centennial and Calumet have each issued a letter of credit supporting 50 percent of the credit agreement. The credit agreement is used to meet the operational needs of the facility.

Dakota Prairie Refining has been determined to be a VIE, and the Company has determined that it is the primary beneficiary as it has an obligation to absorb losses that could be potentially significant to the VIE through WBI Energy's equity investment and Centennial's guarantee of the third-party term loan. Accordingly, the Company consolidates Dakota Prairie Refining in its financial statements and records a noncontrolling interest for Calumet's ownership interest.

Dakota Prairie Refinery has commenced operations. The assets of Dakota Prairie Refining shall be used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining reflected on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2015	2014
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 851**	$ 21,376
Accounts receivable	**7,693**	2,759
Inventories	**13,176**	5,311
Other current assets	**6,215**	4,019
Total current assets	**27,935**	33,465
Net property, plant and equipment	**425,123**	398,984
Deferred charges and other assets:		
Other	**9,626**	3,400
Total deferred charges and other assets	**9,626**	3,400
Total assets	**$ 462,684**	$ 435,849
Liabilities		
Current liabilities:		
Short-term borrowings	**$ 45,500**	$ —
Long-term debt due within one year	**5,250**	3,000
Accounts payable	**24,766**	55,089
Taxes payable	**1,391**	648
Accrued compensation	**938**	727
Other accrued liabilities	**4,953**	899
Total current liabilities	**82,798**	60,363
Long-term debt	**63,750**	69,000
Total liabilities	**$ 146,548**	$ 129,363

Fuel Contract On October 10, 2012, the Coyote Station entered into a new coal supply agreement with Coyote Creek that will replace a coal supply agreement expiring in May 2016. The new agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040.

The new coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal will cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At December 31, 2015, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at December 31, 2015, was $40.1 million.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2015 and 2014:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2015				
Operating revenues	**$ 862,349**	**$ 986,215**	**$ 1,280,500**	**$ 1,062,485**
Operating expenses	**818,680**	**940,887**	**1,170,757**	**1,007,092**
Operating income	**43,669**	**45,328**	**109,743**	**55,393**
Income from continuing operations	**15,160**	**14,057**	**53,400**	**32,077**
Income (loss) from discontinued operations, net of tax	**(324,605)**	**(251,415)**	**(202,626)**	**6,261**
Net income (loss) attributable to the Company	**(305,917)**	**(229,604)**	**(139,448)**	**52,534**
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	**.10**	**.11**	**.32**	**.24**
Discontinued operations, net of tax	**(1.67)**	**(1.29)**	**(1.04)**	**.03**
Earnings (loss) per common share - basic	**(1.57)**	**(1.18)**	**(.72)**	**.27**
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	**.10**	**.11**	**.32**	**.24**
Discontinued operations, net of tax	**(1.67)**	**(1.29)**	**(1.04)**	**.03**
Earnings (loss) per common share - diluted	**(1.57)**	**(1.18)**	**(.72)**	**.27**
Weighted average common shares outstanding:				
Basic	**194,479**	**194,805**	**195,151**	**195,266**
Diluted	**194,566**	**194,838**	**195,169**	**195,324**
2014				
Operating revenues	$ 900,761	$ 952,564	$ 1,213,203	$ 1,048,288
Operating expenses	837,153	890,210	1,094,310	973,720
Operating income	63,608	62,354	118,893	74,568
Income from continuing operations	31,027	29,446	63,639	55,051
Income from discontinued operations, net of tax	25,112	23,881	38,482	27,700
Net income attributable to the Company	56,662	54,106	103,209	84,256
Earnings per common share - basic:				
Earnings before discontinued operations	.17	.16	.33	.29
Discontinued operations, net of tax	.13	.12	.20	.14
Earnings per common share - basic	.30	.28	.53	.43
Earnings per common share - diluted:				
Earnings before discontinued operations	.16	.16	.33	.29
Discontinued operations, net of tax	.14	.12	.20	.14
Earnings per common share - diluted	.30	.28	.53	.43
Weighted average common shares outstanding:				
Basic	189,820	192,060	193,949	194,136
Diluted	190,432	192,659	194,300	194,219

Notes:

- First quarter 2015 reflects a MEPP withdrawal liability of $2.4 million (before tax). For more information, see Note 14.
- Second quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $3.0 million (before tax). For more information, see Note 1.
- Third quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $14.1 million (before tax). For more information, see Note 1.
- Fourth quarter 2014 reflects a MEPP withdrawal liability of approximately $14.0 million (before tax). For more information, see Note 14.
- 2014 and first quarter 2015 have been restated to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations.

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Exploration and Production Activities (Unaudited)

In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. A majority of the sales were completed in the fourth quarter of 2015. At the time the Company committed to a plan to sell Fidelity, the Company stopped the use of the full-cost method of accounting for its oil and natural gas production activities. The assets and liabilities have been classified as held for sale and the results of operations included in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. Prior to the asset sales, Fidelity was significantly involved in the development and production of oil and natural gas resources. For more information, see Note 2.

Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests. The information that follows includes Fidelity's proportionate share of all its oil and natural gas interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to oil and natural gas producing activities at December 31:

	2015 *	2014	2013
		(In thousands)	
Subject to amortization	**$ —**	$ 3,205,036	$ 2,893,010
Not subject to amortization	**—**	132,141	124,869
Total capitalized costs	**—**	3,337,177	3,017,879
Less accumulated depreciation, depletion and amortization	**—**	1,752,566	1,562,116
Net capitalized costs	**$ —**	$ 1,584,611	$ 1,455,763

* Excludes assets held for sale.

Capital expenditures, including those not subject to amortization, related to oil and natural gas producing activities were as follows:

Years ended December 31,	**2015** *	2014 **	2013 **
		(In thousands)	
Acquisitions:			
Proved properties	**$ —**	$ 87,919	$ 1,817
Unproved properties	**—**	138,683	4,608
Exploration	**—**	16,879	26,975
Development	**—**	331,400	355,421
Total capital expenditures	**$ —**	$ 574,881	$ 388,821

* No wells were drilled in 2015.
** Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of oil and natural gas wells of $(9.0) million and $(10.7) million for the years ended December 31, 2014 and 2013, respectively.

The preceding table excludes proceeds from the sales of oil and natural gas properties of $246.6 million and $83.6 million for the years ended December 31, 2014 and 2013, respectively.

The following reflects the results of operations from the Company's oil and natural gas producing activities included in discontinued operations, excluding corporate overhead and financing costs:

Years ended December 31,	**2015**	2014	2013
		(In thousands)	
Income (loss) from discontinued operations	**$ (772,385)**	$ 111,998	$ 110,191

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 proved reserve estimates as of December 31, 2015, 2014 and 2013, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates are current estimates of well operating and future development costs (which include asset retirement 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 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.

Estimates of economically recoverable oil, NGL and natural gas reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2015, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	43,918	7,187	245,011	91,940
Production	(3,286)	(393)	(16,747)	(6,471)
Extensions and discoveries	744	29	681	888
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(16,474)	(6,864)	(202,560)	(57,097)
Revisions of previous estimates	(12,215)	252	(23,854)	(15,939)
Balance at end of year	12,687	211	2,531	13,321

Significant changes in proved reserves for the year ended December 31, 2015, include:

- Sales of proved reserves of (57.1) MMBOE, primarily due to the Company's decision to sell Fidelity and exit the exploration and production business
- Revisions of previous estimates of (15.9) MMBOE, largely the result of lower commodity prices

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2014, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	41,019	6,602	198,445	80,695
Production	(4,919)	(609)	(20,822)	(8,998)
Extensions and discoveries	9,654	3,634	64,420	24,025
Improved recovery	—	—	—	—
Purchases of proved reserves	5,463	—	7,711	6,748
Sales of proved reserves	(4,945)	(3,109)	(40,451)	(14,796)
Revisions of previous estimates	(2,354)	669	35,708	4,266
Balance at end of year	43,918	7,187	245,011	91,940

Significant changes in proved reserves for the year ended December 31, 2014, include:

- Extensions and discoveries of 24.0 MMBOE, primarily due to drilling activity at the Company's East Texas, Bakken and Powder River Basin properties
- Purchases of proved reserves of 6.7 MMBOE, primarily due to the purchase of working interests and leasehold positions in the Powder River Basin
- Sales of proved reserves of (14.8) MMBOE, primarily at the Company's South Texas and Bakken properties
- Revisions of previous estimates of 4.3 MMBOE, largely the result of higher natural gas prices and well performance revisions

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2013, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	33,453	7,153	239,278	80,486
Production	(4,815)	(781)	(28,008)	(10,264)
Extensions and discoveries	13,313	1,333	26,428	19,050
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(1,286)	(25)	(40,055)	(7,987)
Revisions of previous estimates	354	(1,078)	802	(590)
Balance at end of year	41,019	6,602	198,445	80,695

Significant changes in proved reserves for the year ended December 31, 2013, include:

- Extensions and discoveries of 19.1 MMBOE, primarily due to drilling activity and new PUD locations at the Company's Bakken and Paradox Basin properties, as well as new PUD locations at Big Horn and East Texas
- Sales of proved reserves of (8.0) MMBOE, primarily at the Company's Green River Basin property

The following table summarizes the breakdown of the Company's proved reserves between proved developed and PUD reserves at December 31:

	2015	2014	2013
Proved developed reserves:			
Oil (MBbls)	**11,380**	30,130	31,394
NGL (MBbls)	**144**	4,217	5,322
Natural Gas (MMcf)	**2,033**	184,437	176,546
Total (MBOE)	**11,865**	65,086	66,140
PUD reserves:			
Oil (MBbls)	**1,307**	13,788	9,625
NGL (MBbls)	**67**	2,970	1,280
Natural Gas (MMcf)	**498**	60,574	21,899
Total (MBOE)	**1,456**	26,854	14,555
Total proved reserves:			
Oil (MBbls)	**12,687**	43,918	41,019
NGL (MBbls)	**211**	7,187	6,602
Natural Gas (MMcf)	**2,531**	245,011	198,445
Total (MBOE)	**13,321**	91,940	80,695

As of December 31, 2015, the Company had 1.5 MMBOE of PUD reserves, which is a decrease of 25.4 MMBOE from December 31, 2014. The decrease relates to the various asset sales during 2015 and certain PUD reserves becoming uneconomic due to lower commodity prices. At December 31, 2015, the Company did not have any PUD locations that remained undeveloped for five years of more.

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various oil and natural gas interests at December 31 was as follows:

	2014	2013
	(In thousands)	
Future cash inflows	$ 5,185,500	$ 4,507,000
Future production costs	1,856,900	1,734,800
Future development costs	570,200	403,000
Future net cash flows before income taxes	2,758,400	2,369,200
Future income tax expense	686,100	545,200
Future net cash flows	2,072,300	1,824,000
10% annual discount for estimated timing of cash flows	997,400	810,000
Discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$ 1,074,900	$ 1,014,000

Note: Standardized measure not applicable in 2015 as the remaining oil and natural gas properties are held for sale and subject to fair value impairment.

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2014	2013
	(In thousands)	
Beginning of year	$ 1,014,000	$ 883,400
Net revenues from production	(368,900)	(398,000)
Net change in sales prices and production costs related to future production	86,300	162,200
Extensions and discoveries, net of future production-related costs	231,900	366,500
Improved recovery, net of future production-related costs	—	—
Purchases of proved reserves, net of future production-related costs	103,800	—
Sales of proved reserves	(219,300)	(37,800)
Changes in estimated future development costs	65,100	6,700
Development costs incurred during the current year	104,600	141,500
Accretion of discount	109,400	94,600
Net change in income taxes	(33,400)	(141,400)
Revisions of previous estimates	(16,300)	(55,800)
Other	(2,300)	(7,900)
Net change	60,900	130,600
End of year	$ 1,074,900	$ 1,014,000

Note: Standardized measure not applicable in 2015 as the remaining oil and natural gas properties are held for sale and subject to fair value impairment.

Historically, the estimated discounted future cash inflows from estimated future production of proved reserves were computed using prices as previously discussed. Future production and development costs, which include asset retirement costs, attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates to the estimated net future pretax cash flows less the tax basis of the oil and gas properties, adjusted for permanent differences and tax credits.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of oil and natural gas properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs.

Definitions

The following abbreviations and acronyms used in Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Bbl	Barrel
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
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
Bombard Mechanical	Bombard Mechanical, LLC, an indirect wholly owned subsidiary of MDU Construction Services
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Btu	British thermal unit
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
Colorado Court of Appeals	Court of Appeals, State of Colorado
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
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 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
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ESCP	Erosion and Sediment Control Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
LTM	LTM, Incorporated, an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE

Mcf	Thousand cubic feet
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
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
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Nevada State District Court	District Court Clark County, Nevada
NGL	Natural gas liquids
Notice of Civil Penalty	Notice of Civil Penalty Assessment and Order
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RIN	Renewable Identification Number
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States 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
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
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

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2015, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The information required by this item is included in this Form 10-K at Item 8 - Management's Report on Internal Control Over Financial Reporting.

Attestation Report of the Registered Public Accounting Firm

The information required by this item is included in this Form 10-K at Item 8 - Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in the last sentence of the second paragraph under the caption "Item 1. Election of Directors" and under the captions "Item 1. Election of Directors - Director Nominees," "Information Concerning Executive Officers," the first paragraph and the second and third sentences of the second paragraph under "Corporate Governance - Audit Committee," "Corporate Governance - Code of Conduct," the second sentence of the last paragraph under "Corporate Governance - Board Meetings and Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement, which information is incorporated herein by reference.

Item 11. Executive Compensation

The information required by this item is included under the caption "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is included in the Proxy Statement under the caption "Equity Compensation Plan Information" in Item 2. Approval of the Material Terms of the Performance Goals under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan for Purposes of Internal Revenue Code Section 162(m) and under the caption "Security Ownership", which information is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is included under the captions "Related Person Transaction Disclosure," "Corporate Governance - Director Independence" and the second sentence of the third paragraph under "Corporate Governance - Board Meetings and Committees" in the Proxy Statement, which information is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item is included under the caption "Item 3. Ratification of Independent Registered Public Accounting Firm - Accounting and Auditing Matters" in the Proxy Statement, which information is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

2. Financial Statement Schedules

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	2015	2014	2013
		(In thousands)	
Operating revenues	$ 556,112	$ 628,578	$ 549,239
Operating expenses	478,198	547,820	473,917
Operating income	77,914	80,758	75,322
Other income	8,318	5,271	3,709
Interest expense	23,562	21,055	17,386
Income before income taxes	62,670	64,974	61,645
Income taxes	15,882	16,819	13,520
Equity in earnings of subsidiaries from continuing operations	103,162	134,903	120,929
Net income attributable to the Company from continuing operations	149,950	183,058	169,054
Equity in earnings (loss) of subsidiaries from discontinued operations	(772,385)	115,175	109,879
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$ (623,120)	$ 297,548	$ 278,248
Comprehensive income (loss)	$ (617,480)	$ 294,335	$ 289,449

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Balance Sheets

December 31,	2015	2014
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 2,921	$ 6,120
Receivables, net	70,511	91,493
Accounts receivable from subsidiaries	33,129	32,691
Inventories	16,883	33,584
Deferred income taxes	2,846	547
Prepayments and other current assets	7,876	70,852
Total current assets	134,166	235,287
Investments	66,784	64,446
Investment in subsidiaries	1,722,351	2,590,283
Property, plant and equipment	2,378,994	1,984,956
Less accumulated depreciation, depletion and amortization	711,209	660,026
Net property, plant and equipment	1,667,785	1,324,930
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	186,187	163,408
Total deferred charges and other assets	190,999	168,220
Total assets	$ 3,782,085	$ 4,383,166
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 109	$ 109
Accounts payable	54,275	48,088
Accounts payable to subsidiaries	6,622	30,863
Taxes payable	10,995	10,583
Dividends payable	36,784	35,607
Accrued compensation	7,539	11,227
Other accrued liabilities	40,931	36,488
Total current liabilities	157,255	172,965
Long-term debt	625,155	508,164
Deferred credits and other liabilities:		
Deferred income taxes	257,915	251,067
Other liabilities	345,255	316,929
Total deferred credits and other liabilities	603,170	567,996
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 195,804,665 shares in 2015 and 194,754,812 shares in 2014	195,805	194,755
Other paid-in capital	1,230,119	1,207,188
Retained earnings	996,355	1,762,827
Accumulated other comprehensive loss	(37,148)	(42,103)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,381,505	3,119,041
Total stockholders' equity	2,396,505	3,134,041
Total liabilities and stockholders' equity	$ 3,782,085	$ 4,383,166

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2015	2014	2013
		(In thousands)	
Net cash provided by operating activities	$ **255,273**	$ 208,208	$ 188,259
Investing activities:			
Capital expenditures	**(349,985)**	(223,251)	(211,013)
Net proceeds from sale or disposition of property and other	**3,268**	1,552	20,624
Investments in and advances to subsidiaries	**(7,000)**	(134,451)	(1,016)
Advances from subsidiaries	**100,000**	64,500	10,000
Investments	**5**	(794)	613
Net cash used in investing activities	**(253,712)**	(292,444)	(180,792)
Financing activities:			
Issuance of long-term debt	**224,185**	148,959	77,924
Repayment of long-term debt	**(108,008)**	(76,432)	(85)
Proceeds from issuance of common stock	**21,898**	150,060	14,554
Dividends paid	**(142,835)**	(136,712)	(98,405)
Excess tax benefit on stock-based compensation	**—**	3,326	—
Tax withholding on stock-based compensation	**—**	(3,896)	—
Net cash provided by (used in) financing activities	**(4,760)**	85,305	(6,012)
Increase (decrease) in cash and cash equivalents	**(3,199)**	1,069	1,455
Cash and cash equivalents - beginning of year	**6,120**	5,051	3,596
Cash and cash equivalents - end of year	$ **2,921**	$ 6,120	$ 5,051

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income (loss) from subsidiaries is reported as equity in earnings (loss) of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings (loss) per common share Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Note 1 of Notes to Consolidated Financial Statements for information on the computation of earnings (loss) per common share.

Note 2 - Debt The Company has long-term debt obligations outstanding of $625.3 million at December 31, 2015, with annual maturities of $100,000 in 2016, $100,000 in 2017, $100.1 million in 2018, $44.6 million in 2019 and $480.4 million scheduled to mature in years after 2020.

For more information on debt, see Note 7 of Notes to Consolidated Financial Statements.

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $110.6 million, $105.6 million and $77.6 million for the years ended December 31, 2015, 2014 and 2013, respectively.

MDU RESOURCES GROUP, INC.

Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2015, 2014 and 2013

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
		(In thousands)			
Allowance for doubtful accounts:					
2015	**$ 9,511**	**$ 11,343**	**$ 1,012**	**$ 12,031**	**$ 9,835**
2014	10,085	8,548	1,335	10,457	9,511
2013	10,818	5,725	1,395	7,853	10,085

* Recoveries.
** Uncollectible accounts written off.

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

3. Exhibits

3(a) Restated Certificate of Incorporation of MDU Resources Group, Inc., as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

3(b) Bylaws of MDU Resources Group, Inc., as amended and restated on April 2, 2015, filed as Exhibit 3 to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*

4(a) Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(b) First Supplemental Indenture, dated as of November 17, 2009, between MDU Resources Group, Inc. and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

4(c) Centennial Energy Holdings, Inc. Amended and Restated Master Shelf Agreement, effective as of April 29, 2005, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America and certain investors described therein, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(d) Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(e) Letter Amendment No. 2 to Amended and Restated Master Shelf Agreement, dated December 19, 2007, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment**

4(f) Letter Amendment No. 3 to Amended and Restated Master Shelf Agreement, dated December 18, 2015, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment**

4(g) MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

4(h) First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

4(i) Second Amendment to Credit Agreement, dated May 8, 2014, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

4(j) Third Amended and Restated Credit Agreement, dated May 8, 2014, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

4(k) Waiver, dated December 29, 2015, under Third Amended and Restated Credit Agreement, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto**

4(l) MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America and the holders of the notes thereunder, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*

4(m) Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*

4(n) Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(o) First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*

4(p) Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*

4(q) Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a) Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(b) Director Compensation Policy, as amended May 15, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

+10(c) Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*

+10(d) Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(e) MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(f) MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016**

+10(g) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended March 4, 2013, and Rules and Regulations, as amended March 4, 2013, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2013, filed on May 7, 2013, in File No. 1-3480*

+10(h) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended November 14, 2012, filed as Exhibit 10.1 to Form 8-K dated November 14, 2012, filed on November 20, 2012, in File No. 1-3480*

+10(i) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 12, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*

+10(j) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2015, filed as Exhibit 10.3 to Form 8-K dated February 11, 2015, filed on February 18, 2015, in File No. 1-3480*

+10(k) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2015, filed as Exhibit 10.2 to Form 8-K dated February 11, 2015, filed on February 18, 2015, in File No. 1-3480*

+10(l) Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(m) Form of Amendment No. 1 to Indemnification Agreement, filed as Exhibit 10.2 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(n) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 9, 2016**

+10(o) Employment Letter for J. Kent Wells, dated March 9, 2011, filed as Exhibit 10(v) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(p) MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as adopted November 17, 2011, filed as Exhibit 10(x) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(q) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(r) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*

+10(s) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(t) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(u) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011, filed as Exhibit 10(ac) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(v) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 24, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(w) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(x) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(y) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2012, filed on February 28, 2013, in File No. 1-3480*

+10(z) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(aa) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(ab) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(ac) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 31, 2013, filed as Exhibit 10(aa) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*

+10(ad) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*

+10(ae) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 5, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

+10(af) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated July 7, 2014, filed as Exhibit 4.20 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*

+10(ag) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 18, 2014, filed as Exhibit 4.21 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*

+10(ah) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 30, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2014, filed on November 7, 2014, in File No. 1-3480*

+10(ai) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 25, 2014, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(aj) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014, filed as Exhibit 10(ai) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(ak) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014, filed as Exhibit 10(aj) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(al) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 30, 2014, filed as Exhibit 10(ak) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(am) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated February 17, 2015, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*

+10(an) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2015, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*

+10(ao) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2015, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2015, filed on August 4, 2015, in File No. 1-3480*

+10(ap) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 19, 2015**

+10(aq) Employment Letter for Jeffrey S. Thiede, dated May 16, 2013, filed as Exhibit 10(ab) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*

+10(ar) Agreement with J. Kent Wells, dated January 22, 2015, filed as Exhibit 10 to Form 8-K dated January 20, 2015, filed on January 23, 2015, in File No. 1-3480*

+10(as)	Waiver and Voluntary Release, dated July 17, 2015, between Steven L. Bietz and WBI Holdings, Inc., filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2015, filed on August 4, 2015, in File No. 1-3480*
+10(at)	Martin A. Fritz Offer Letter, dated July 1, 2015, filed as Exhibit 10.2 to Form 8-K dated June 30, 2015, filed on July 2, 2015, in File No. 1-3480*
+10(au)	Form of 2015 Annual Incentive Award Agreement for Patrick L. O'Bryan under the Long-Term Performance-Based Incentive Plan, filed as Exhibit 10.1 to Form 8-K/A dated February 18, 2015, filed February 18, 2015, in File No. 1-3480*
+10(av)	Patrick L. O'Bryan November 2014 Incentive Opportunity, filed as Exhibit 10.2 to Form 8-K/A dated February 18, 2015, filed on February 18, 2015, in File No. 1-3480*
+10(aw)	Patrick L. O'Bryan Sales Bonus Incentive Award Opportunity granted May 13, 2015**
+10(ax)	David C. Barney 2015 Additional Annual Incentive Award Opportunity under the Long-Term Performance-Based Incentive Plan granted February 12, 2015**
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23	Consent of Independent Registered Public Accounting Firm**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**
99(a)	Equity Distribution Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated May 20, 2013, filed on May 20, 2013, in File No. 1-3480*
99(b)	First Amendment to Equity Distribution Agreement, dated December 2, 2013, entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 99(c) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2015, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vii) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (viii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.

** Filed herewith.

\+ Management contract, compensatory plan or arrangement.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MDU Resources Group, Inc.

Date: February 19, 2016 By: /s/ David L. Goodin

David L. Goodin
(President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the date indicated.

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 19, 2016
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 19, 2016
/s/ Nathan W. Ring Nathan W. Ring (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 19, 2016
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 19, 2016
/s/ Thomas Everist Thomas Everist	Director	February 19, 2016
/s/ Karen B. Fagg Karen B. Fagg	Director	February 19, 2016
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 19, 2016
/s/ A. Bart Holaday A. Bart Holaday	Director	February 19, 2016
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 19, 2016
/s/ William E. McCracken William E. McCracken	Director	February 19, 2016
/s/ Patricia L. Moss Patricia L. Moss	Director	February 19, 2016
/s/ John K. Wilson John K. Wilson	Director	February 19, 2016

MDU RESOURCES GROUP, INC.

1200 W. Century Ave.
Bismarck, ND 58503
Mailing address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000
www.MDU.com

David L. Goodin
President and
Chief Executive Officer

March 16, 2016

To Our Stockholders:

Please join us for the 2016 Annual Meeting of Stockholders. The meeting will be held on Tuesday, April 26, 2016, at 11:00 a.m., Central Daylight Saving Time, at 909 Airport Road, Bismarck, North Dakota.

The formal matters are described in the accompanying Notice of Annual Meeting of Stockholders and Proxy Statement. We also will have a brief report on current matters of interest. Lunch will be served following the meeting.

We were pleased with the stockholder response for the 2015 Annual Meeting at which 89.82 percent of the common stock was represented in person or by proxy. We hope for an even greater representation at the 2016 meeting.

You may vote your shares by telephone, by the Internet, or by returning the enclosed proxy card. Representation of your shares at the meeting is very important. We urge you to submit your proxy promptly.

Brokers may not vote your shares on three of the four matters to be presented if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

All stockholders who find it convenient to do so are cordially invited and urged to attend the meeting in person. Registered stockholders will receive a request for admission ticket(s) with their proxy card that can be completed and returned to us postage-free. Stockholders whose shares are held in the name of a bank or broker will not receive a request for admission ticket(s). They should, instead: (1) call (701) 530-1000 to request an admission ticket(s), (2) obtain a statement from their bank or broker showing proof of stock ownership as of March 1, 2016, and (3) present their admission ticket(s), the stock ownership statement, and photo identification, such as a driver's license, at the annual meeting. Directions to the meeting will be included with your admission ticket.

I hope you will find it possible to attend the meeting.

Sincerely yours,

David L. Goodin

MDU RESOURCES GROUP, INC.

1200 West Century Avenue

Mailing Address:
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(701) 530-1000

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS TO BE HELD APRIL 26, 2016

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to be Held on April 26, 2016

The 2016 Notice of Annual Meeting and Proxy Statement and 2015 Annual Report to Stockholders are available at www.mdu.com/proxymaterials.

March 16, 2016

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of MDU Resources Group, Inc. will be held at 909 Airport Road, Bismarck, North Dakota, on Tuesday, April 26, 2016, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

(1) Election of ten directors nominated by the board of directors for one-year terms;

(2) Approval of the material terms of the performance goals under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan for purposes of Internal Revenue Code Section 162(m);

(3) Ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2016;

(4) Approval, on a non-binding advisory basis, of the compensation of the company's named executive officers; and

(5) Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.

The board of directors has set the close of business on March 1, 2016, as the record date for the determination of common stockholders who will be entitled to notice of, and to vote at, the meeting and any adjournment(s) thereof.

All stockholders who find it convenient to do so are cordially invited and urged to attend the meeting in person. Registered stockholders will receive a request for admission ticket(s) with their proxy card that can be completed and returned to us postage-free. Stockholders whose shares are held in the name of a bank or broker will not receive a request for admission ticket(s). They should, instead: (1) call (701) 530-1000 to request an admission ticket(s), (2) obtain a statement from their bank or broker showing proof of stock ownership as of March 1, 2016, and (3) present their admission ticket(s), the stock ownership statement, and photo identification, such as a driver's license, at the annual meeting. Directions to the meeting will be included with your admission ticket. We look forward to seeing you.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary

PROXY STATEMENT

The board of directors of MDU Resources Group, Inc. is furnishing this proxy statement beginning March 16, 2016, to solicit your proxy for use at our annual meeting of stockholders on April 26, 2016, and any adjournment(s) thereof. We are soliciting proxies principally by mail, but directors, officers, and employees of MDU Resources Group, Inc. or its subsidiaries may solicit proxies personally, by telephone or by electronic media, without compensation other than their regular compensation. Okapi Partners LLC additionally will solicit proxies for approximately $8,000 plus out-of-pocket expenses. We will pay the cost of soliciting your proxy and reimburse brokers and others for forwarding proxy materials to you.

The Securities and Exchange Commission's e-proxy rules allow companies to post their proxy materials on the Internet and provide only a Notice of Internet Availability of Proxy Materials to stockholders as an alternative to mailing full sets of proxy materials except upon request. For 2016, we have elected to use the Securities and Exchange Commission's full set delivery option, which means that while we are posting our proxy materials online, we are also mailing a full set of our proxy materials to our stockholders. We believe that mailing a full set of proxy materials will help ensure that a majority of outstanding shares of our common stock are present in person or represented by proxy at our meeting. We also hope to help maximize stockholder participation. Therefore, even if you previously consented to receiving your proxy materials electronically, you will receive a full set of proxy materials in the mail for this year's annual meeting. However, we will continue to evaluate the option of providing only a Notice of Internet Availability of Proxy Materials to some or all of our stockholders in the future.

VOTING INFORMATION

Who may vote? You may vote if you owned shares of our common stock at the close of business on March 1, 2016. You may vote each share that you owned on that date on each matter presented at the meeting and any adjournment(s) thereof. As of March 1, 2016, we had 195,304,376 shares of common stock outstanding entitled to one vote per share.

What am I voting on? You are voting on:

- election of ten directors nominated by the board of directors for one-year terms
- approval of the material terms of the performance goals under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan for purposes of Internal Revenue Code Section 162(m)
- ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2016
- approval, on a non-binding advisory basis, of the compensation of the company's named executive officers and
- any other business that is properly brought before the meeting or any adjournment(s) thereof.

What vote is required to pass an item of business? A majority of our outstanding shares of common stock entitled to vote must be present in person or represented by proxy to hold the meeting.

If you hold shares through an account with a bank or broker, the bank or broker may vote your shares on some matters even if you do not provide voting instructions. Brokerage firms have the authority under the New York Stock Exchange rules to vote shares on certain matters when their customers do not provide voting instructions. However, on other matters, when the brokerage firm has not received voting instructions from its customers, the brokerage firm cannot vote the shares on those matters and a "broker non-vote" occurs. **This means that brokers may not vote your shares on items 1, 2, and 4 if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.**

Item 1 – Election of Directors

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected, directors will be elected by a plurality of the votes cast. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies may vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes “against” than votes “for” election at our annual meeting of stockholders and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee’s recommendation no later than 90 days following the date of the annual meeting.

Item 2 - Approval of the Material Terms of the Performance Goals under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan for Purposes of Internal Revenue Code Section 162(m)

For purposes of Internal Revenue Code Section 162(m), approval of Item 2 requires a majority of votes cast to be in favor of approval. Broker non-vote shares and abstentions will not count as votes cast.

Item 3 – Ratification of the Appointment of Deloitte & Touche LLP as the Company’s Independent Registered Public Accounting Firm for 2016

Approval of Item 3 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the item. Abstentions will count as votes “against” the item.

Item 4 – Approval, on a Non-Binding Advisory Basis, of the Compensation of the Company’s Named Executive Officers

Approval of Item 4 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the item. Abstentions will count as votes “against” the item. Broker non-vote shares are not entitled to vote on the item and, therefore, are not counted in the vote.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock “for” all directors nominated by the board of directors and “for” items 2, 3, and 4.

How do I vote? If you are a stockholder of record, you may vote by:

- calling the toll free telephone number on the enclosed proxy card
- using the Internet as described on the enclosed proxy card or
- returning the enclosed proxy card in the envelope provided.

If you are a beneficial owner, you must provide voting instructions to your bank, broker, or other nominee to ensure your shares are voted as you would like. You should follow their instructions.

You may also vote in person at the meeting. However, if you are the beneficial owner of the shares, you must obtain a legal proxy from your bank or broker and present it at the meeting. A legal proxy identifies you, states the number of shares you own, and gives you the right to vote those shares. Without a legal proxy we cannot identify you as the beneficial owner of the shares or know how many shares you have to vote.

Can I change my vote? Yes.

If you are a beneficial owner, such as where your shares are held of record by a bank, broker, or other nominee, you may change your vote by providing later dated voting instructions to your bank, broker, or other nominee in accordance with their procedures or by obtaining a legal proxy and voting in person at the meeting, as set forth above.

If you are a stockholder of record, you may revoke your proxy and change your vote by:

- submitting a written revocation to the corporate secretary before the meeting
- submitting a proxy bearing a later date to the corporate secretary before the meeting or
- voting in person at the meeting.

ITEM 1. ELECTION OF DIRECTORS

All nominees for director are nominated to serve one-year terms until the annual meeting of stockholders in 2017 and until their respective successors are elected and qualified, or until their earlier resignation, removal from office, or death.

We have provided information below about our nominees, all of whom are incumbent directors, including their ages, years of service as directors, business experience, and service on other boards of directors, including any other directorships held during the past five years. We have also included information about each nominee's specific experience, qualifications, attributes, or skills that led the board to conclude that he or she should serve as a director of MDU Resources Group, Inc. at the time we file our proxy statement, in light of our business and structure. Unless we specifically note below, no corporation or organization referred to below is a subsidiary or other affiliate of MDU Resources Group, Inc.

Director Nominees

Thomas Everist
66

Director Since 1995
Compensation Committee

Mr. Everist has served as president and chairman of The Everist Company, Sioux Falls, South Dakota, an aggregate, concrete, and asphalt production company, since April 15, 2002. He has been a managing member of South Maryland Creek Ranch, LLC, a land development company, since June 2006, president of SMCR, Inc., an investment company, since June 2006, and a managing member of MCR Builders, LLC, which provides residential building services to South Maryland Creek Ranch, LLC, since November 2014. He was previously president and chairman of L.G. Everist, Inc., Sioux Falls, South Dakota, an aggregate production company, from 1987 to April 15, 2002. He held a number of positions in the aggregate and construction industries prior to assuming his current position with The Everist Company. He is a director of Showplace Wood Products, Sioux Falls, South Dakota, a custom cabinets manufacturer, and has been a director of publicly traded Raven Industries, Inc., Sioux Falls, South Dakota, a general manufacturer of electronics, flow controls, and engineered films since 1996, and its chairman of the board since April 1, 2009. Mr. Everist has served as a director and chairman of the board of Everist Genomics, Inc., Ann Arbor, Michigan, which provides solutions for personalized medicines since 2002. He served as Everist Genomics' chief executive officer from August 2012 to December 2012. He was a director of Angiologix Inc., Mountain View, California, a medical diagnostic device company, from July 2010 through October 2011 when it was acquired by Everist Genomics, Inc. He has been a director of Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, since April 2011.

Mr. Everist attended Stanford University where he received a bachelor's degree in mechanical engineering and a master's degree in construction management. He is active in the Sioux Falls community and currently serves as a director on the Sanford Health Foundation, a nonprofit charitable health services organization, and co-founder and chairman of the board of Searching for Solutions Institute, a nonprofit public foundation that provides leaders with resources to address critical social issues. From July 2001 to June 2006, he served on the South Dakota Investment Council, the state agency responsible for prudently investing state funds.

The board concluded that Mr. Everist should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. A significant portion of MDU Resources Group, Inc.'s earnings is derived from its construction services and aggregate mining businesses. Mr. Everist has considerable business experience in this area, with more than 42 years in the aggregate and construction materials industry. He has also demonstrated success in his business and leadership skills, serving as president and chairman of his companies for over 28 years. We value other public company board service. Mr. Everist has experience serving as a director and chairman of another public company, which enhances his contributions to our board. His leadership skills and experience with his own companies and on other boards enable him to be an effective board member and compensation committee chairman. Mr. Everist is our longest serving board member, providing 21 years of board experience as well as extensive knowledge of our business.

Karen B. Fagg

Age 62

Director Since 2005

Compensation Committee

Nominating and Governance Committee

Ms. Fagg served as vice president of DOWL LLC, d/b/a DOWL HKM, an engineering and design firm, from April 2008 until her retirement on December 31, 2011. Ms. Fagg was president from April 1, 1995 to June 2000, and chairman, chief executive officer, and majority owner from June 2000 through March 2008 of HKM Engineering, Inc., Billings, Montana, an engineering and physical science services firm. HKM Engineering, Inc. merged with DOWL LLC on April 1, 2008. Ms. Fagg was employed with MSE, Inc., Butte, Montana, an energy research and development company, from 1976 through 1988, and from 1993 to April 1995 she served as vice president of operations and corporate development director. From 1989 through 1992, Ms. Fagg served a four-year term as director of the Montana Department of Natural Resources and Conservation, Helena, Montana, the state agency charged with promoting stewardship of Montana's water, soil, energy, and rangeland resources; regulating oil and gas exploration and production; and administering several grant and loan programs.

Ms. Fagg has a bachelor's degree in mathematics from Carroll College in Helena, Montana. In 2013, she served on a three-person selection committee appointed by the Attorney General to identify trustees for the Montana Healthcare Foundation Board. She is a board member of the First Interstate BancSystem Foundation, which has a strong commitment to community, and has been a member of the Billings Catholic Schools Board since December 2011, serving as its vice-chair and a member of its capital campaign committee. Ms. Fagg started a new term on the board for St. Vincent's Healthcare in January 2016, having previously served from October 2003 until October 2009, including a term as board chair. She served on the Billings Chamber of Commerce from July 2009 to July 2015, including a term as its chair from July 2013 to July 2014, and on the Montana Justice Foundation, whose mission is to achieve equal access to justice for all Montanans through effective funding and leadership, from 2013 into 2015. She also served on the board of Deaconess Billings Clinic Health System from 1994 to 2002, as a member of the Board of Trustees of Carroll College from 2005 through 2010, and on the board of advisors of the Charles M. Bair Family Trust from 2008 to July 2011, including a term as board chair. From 2007 until December 31, 2011, she was a member of the Montana State University Engineering Advisory Council, whose responsibilities include evaluating the mission and goals of the College of Engineering and assisting in the development and implementation of the college's strategic plan. From 2002 through 2006, she served on the Montana Board of Investments, the state agency responsible for prudently investing state funds. From 2001 to 2005, she served on the board of Montana State University's Advanced Technology Park. From 1998 through 2006, she served on the ZooMontana Board and as vice chair from 2005 through 2006.

The board concluded that Ms. Fagg should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Construction and engineering, energy, and the responsible development of natural resources are all important aspects of our business. Ms. Fagg has business experience in all these areas, including 17 years of construction and engineering experience at DOWL HKM and its predecessor, HKM Engineering, Inc., where she served as vice president, president, chief executive officer, and chairman. Ms. Fagg also has 14 years of experience in energy research and development at MSE, Inc., where she served as vice president of operations and corporate development director, and four years focusing on stewardship of natural resources as director of the Montana Department of Natural Resources and Conservation. In addition to her industry experience, Ms. Fagg brings to our board over 20 years of business leadership and management experience, including over 8 years as president, chief executive officer, and chairman of her own company, as well as knowledge and experience acquired through her service on a number of Montana state and community boards.

David L. Goodin

Age 54

Director Since 2013

President and Chief Executive Officer

Mr. Goodin was elected president and chief executive officer and a director of the company effective January 4, 2013. Prior to that, he served as chief executive officer and president of Intermountain Gas Company effective October 2008, chief executive officer of Cascade Natural Gas Corporation, Montana-Dakota Utilities Co., and Great Plains Natural Gas Co. effective June 2008, president of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective March 2008, and president of Cascade Natural Gas Corporation effective July 2007. He began his career with the company in 1983 at Montana-Dakota Utilities Co., where he served as a division electrical engineer effective

May 1983, division electric superintendent effective February 1989, electric systems supervisor effective August 1993, electric systems manager effective April 1999, vice president-operations effective January 2000, and executive vice president-operations and acquisitions effective January 2007. He additionally serves as an executive officer and as chairman of the company's principal subsidiaries, and of the managing committees of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.

Mr. Goodin has a bachelor of science degree in electrical and electronics engineering from North Dakota State University, a masters in business administration from the University of North Dakota, and has completed the Advanced Management Program at Harvard School of Business. Mr. Goodin is a registered professional engineer in North Dakota. He is a member of the U.S. Bancorp Western North Dakota Advisory Board. Mr. Goodin is involved in numerous civic organizations, including serving on the board of directors of Sanford Bismarck, an integrated health system dedicated to the work of health and healing, Sanford Living Center, and the North Dakota State University Alumni Association. He also serves on the Board of Trustees for the Missouri Valley YMCA, the Bismarck State College Foundation, and the University of Mary. He is a past board member of several industry associations, including the American Gas Association, the Edison Electric Institute, the North Central Electric Association, the Midwest ENERGY Association, and the North Dakota Lignite Council. Mr. Goodin received the University of Mary Entrepreneurship Award in 2009.

The board concluded that Mr. Goodin should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. As chief executive officer of MDU Resources Group, Inc., Mr. Goodin is the only officer of the company on our board. With over 32 years of significant, hands-on experience at our company, Mr. Goodin's long history and deep knowledge and understanding of MDU Resources Group, Inc., its operating companies, and its lines of business bring continuity to the board. Mr. Goodin has demonstrated his leadership abilities and his commitment to our company through his long service to the company, including as chief executive officer and president of the four utility companies. He demonstrated strong leadership skills in integrating Cascade Natural Gas Corporation and Intermountain Gas Company while meeting and exceeding profitability goals. The board's unanimous election of Mr. Goodin to serve as our president and chief executive officer in January 2013 was in recognition of the board's belief that he has the strategic vision, operational experience, passion, and values to lead the future growth of the company. The board believes these characteristics make him well-suited to serve on our board, particularly in this challenging economic environment.

Mark A. Hellerstein

Age 63

Director Since 2013

Audit Committee

Mr. Hellerstein was chief executive officer of St. Mary Land & Exploration Company (now SM Energy Company), an energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids, from 1995 until February 2007; he was president from 1992 until June 2006 and executive vice president and chief financial officer from 1991 until 1992. He was first elected to the board of St. Mary in 1992 and served as chairman of the board from 2002 until May 2009. Prior to joining St. Mary, from 1980 to 1991 Mr. Hellerstein's career included positions as chief financial officer of CoCa Mines Inc., which mined and extracted minerals from lands previously held by the public through the Bureau of Land Management; American Golf Corporation, which manages and owns golf courses in the United States; and Worldwide Energy Corporation, an oil and gas acquisition, exploration, development, and production company with operations in the United States and Canada. Mr. Hellerstein served on the board of directors of Transocean Inc., a leading provider of offshore drilling services for oil and gas wells, from December 2006 to November 2007.

Mr. Hellerstein's leadership has been recognized with induction into the Rocky Mountain Oil and Gas Hall of Fame, and Ernst & Young named Mr. Hellerstein both Rocky Mountain and National Entrepreneur of the Year in 2005 and 2006, respectively. He graduated number one in his class with a bachelor's degree in accounting from the University of Colorado. Mr. Hellerstein is a certified public accountant (CPA), on inactive status. He received the Elijah Watts Sells Gold Medal award for achieving the highest score in the United States on the November 1974 CPA exam out of 38,000 participants. Mr. Hellerstein has served on the board for Community Resources Inc. since September 2013, which is a nonprofit organization that brings programs into the Denver Public Schools to enhance education. He served as a board director on the Denver Children's Advocacy Center (Center) from August 2006 until December 2011, including as chairman for the last three years, and continues to participate in and fund the Center's Safe from the Start Program. The Center's mission is to provide a continuum of care for traumatized children and their families.

The board concluded that Mr. Hellerstein should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. Hellerstein has extensive business experience, recognized excellence, and demonstrated success and leadership, including in the energy industry, as a result of his 17 years of senior management experience and service as board chairman of St. Mary. His skills and experience enable him to contribute independent insight into the company's business and operations and the economic environment and long-term strategic issues the company faces. As a certified public accountant, on inactive status, with extensive financial experience as a result of his employment as chief financial officer with several companies, including public companies, Mr. Hellerstein contributes significant finance and accounting knowledge to our board and audit committee. His financial expertise assists the board in its oversight of the company's financial reporting and financial risk management functions, and supports his service on the audit committee. His service on the board of two publicly traded companies has provided him substantial insight into governance matters, which enhances his contributions to our board. Mr. Hellerstein also brings to the board his knowledge of local, state, and regional issues involving the Rocky Mountain region where we have important operations.

A. Bart Holaday

Age 73

Director Since 2008
Audit Committee
Nominating and Governance Committee

Mr. Holaday headed the Private Markets Group of UBS Asset Management and its predecessor entities for 15 years prior to his retirement in 2001, during which time he managed more than $19 billion in investments. Prior to that he was vice president and principal of the InnoVen Venture Capital Group, a venture capital investment firm. He was founder and president of Tenax Oil and Gas Corporation, an onshore Gulf Coast exploration and production company, from 1980 through 1982. He has four years of senior management experience with Gulf Oil Corporation, a global energy and petrochemical company, and eight years of senior management experience with the federal government, including the Department of Defense, Department of the Interior, and the Federal Energy Administration. He is currently the president and owner of Dakota Renewable Energy Fund, LLC, which invests in small companies in North Dakota. He is a member of the investment advisory board of Commons Capital LLC, a venture capital firm; is a director of Hull Investments, LLC, a private entity that combines nonprofit activities and investments; serves on the Board of Trustees for the University of Jamestown; is a member of the board of directors of Adams Street Partners, LLC, a private equity investment firm, Alerus Financial, a financial services company, the United States Air Force Academy Endowment (former chairman), the Falcon Foundation (director and former vice president), which provides scholarships to Air Force Academy applicants, the Center for Innovation Foundation at the University of North Dakota (trustee and former chairman), and Discover Goodwill of southern and western Colorado, a nonprofit organization providing job training, placement, and retention programs for people transitioning from welfare to work; and is chairman and chief executive officer of the Dakota Foundation, a nonprofit foundation that fosters social entrepreneurship. He is a past member of the board of directors of the University of North Dakota Foundation, National Venture Capital Association, Walden University, and the U.S. Securities and Exchange Commission advisory committee on the regulation of capital markets, and is a past member of the board of trustees for The Colorado Springs Child Nursery Centers Foundation, a nonprofit organization that supports the operations of Early Connections Learning Centers, a nonprofit child care organization in Colorado.

Mr. Holaday has a bachelor's degree in engineering sciences from the U.S. Air Force Academy. He was a Rhodes Scholar, earning a bachelor's degree and a master's degree in politics, philosophy, and economics from Oxford University. He also earned a law degree from George Washington Law School and is a Chartered Financial Analyst. In 2005, he was awarded an honorary Doctor of Letters from the University of North Dakota.

The board concluded that Mr. Holaday should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. Holaday has extensive business knowledge and experience and has demonstrated success and leadership, including in the energy and financial management industries. He founded and served as president of Tenax Oil and Gas Corporation. He has four years experience in senior management with Gulf Oil Corporation and 15 years of experience managing private equity investments, as the head of the Private Markets Group of UBS Asset Management and its predecessor organizations. Mr. Holaday brings to the board extensive finance and investment experience, as well as business development skills acquired through his work at UBS Asset Management, Tenax Oil and Gas Corporation, Gulf Oil Corporation, and several private equity investment firms. This enhances the knowledge of the board and provides useful insights and guidance to management in connection not only with our energy related businesses, but with all of our businesses. His significant experience in finance supports his service on the audit committee.

Dennis W. Johnson

Age 66

Director Since 2001

Audit Committee

Mr. Johnson is chairman, president, and chief executive officer of TMI Corporation, and chairman and chief executive officer of TMI Systems Design Corporation, TMI Transport Corporation, and TMI Storage Systems Corporation, all of Dickinson, North Dakota, manufacturers of casework and architectural woodwork. He has been employed at TMI since 1974 serving as president or chief executive officer since 1982. Mr. Johnson served as president of the Dickinson City Commission for fifteen years. He served as a director of the Federal Reserve Bank of Minneapolis from 1993 through 1998. He is a past member and chairman of the Theodore Roosevelt Medora Foundation.

Mr. Johnson has a bachelor of science degree in electrical and electronics engineering, as well as a master of science degree in industrial engineering from North Dakota State University. He has served on numerous industry, state, and community boards, including the North Dakota Workforce Development Council (chairperson), the Decorative Laminate Products Association, the North Dakota Technology Corporation, St. Joseph Hospital Life Care Foundation, St. John Evangelical Lutheran Church, Dickinson State University Foundation, the executive operations committee of the University of Mary Harold Schafer Leadership Center, the Dickinson United Way, and the business advisory council of the Steffes Corporation, a metal manufacturing and engineering firm. He also served on North Dakota Governor Sinner's Education Action Commission, the North Dakota Job Service Advisory Council, the North Dakota State University President's Advisory Council, North Dakota Governor Schafer's Transition Team, and chaired North Dakota Governor Hoeven's Transition Team. He has received numerous awards, including the 1991 Regional Small Business Person of the Year Award and the Greater North Dakotan Award.

The board concluded that Mr. Johnson should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. Johnson has over 41 years of experience in business management, manufacturing, and finance, and has demonstrated his success in these areas, holding positions as chairman, president, and chief executive officer of TMI for 34 years, as well as through his prior service as a director of the Federal Reserve Bank of Minneapolis. His finance experience and leadership skills enable him to make valuable contributions to our audit committee, which he has chaired for twelve years. As a result of his service on a number of state and local organizations in North Dakota, Mr. Johnson has significant knowledge of local, state, and regional issues involving North Dakota, a state where we have significant operations and assets.

William E. McCracken

Age 73

Director Since 2013

Compensation Committee

Nominating and Governance Committee

Mr. McCracken served as chief executive officer of CA, Inc., one of the world's largest information technology management software companies, from January 2010 until January 7, 2013, after which he served as executive adviser to the new chief executive officer until March 31, 2013, and after that as a consultant to the company until December 31, 2013. Mr. McCracken was a director of CA, Inc. from May 2005 until January 7, 2013, serving as non-executive chairman of the board from June 2007 to September 2009, interim executive chairman from September 2009 to January 2010, and executive chairman from January 2010 to May 2010. He is president of Executive Consulting Group, LLC, a general business consulting firm, since 2002. During his 36-year career with International Business Machines Corporation, a manufacturer of information processing products and a technology, software, and networking systems manufacturer and developer, Mr. McCracken held a number of executive positions, including general manager of IBM printing systems division from 1998 to 2001, general manager of marketing, sales, and distribution for IBM PC Company from 1994 to 1998, and president of IBM's EMEA and Asia Pacific PC Company from 1993 to 1994. From 1995 to 2001, he served on IBM's Chairman's Worldwide Management Council, a group of the top 30 executives at IBM. Mr. McCracken was a director of IKON Office Solutions, Inc., a provider of document management systems and services, from 2003 to 2008, where he served on its audit committee, compensation committee, and strategy committee at various points in time during his tenure as a director.

Mr. McCracken has a bachelor of science degree in physics and mathematics from Shippensburg University. He has served on the board of the National Association of Corporate Directors (NACD), a nonprofit membership organization for corporate board members, since 2010, and was named by the NACD as one of the top 100 most influential people in the boardroom in 2009. He served on that organization's 2009 blue ribbon commission on risk governance, co-chaired its blue ribbon commission on board diversity in 2012, and co-chaired its blue ribbon commission on the board and long-term value creation in 2015. He is chair of the advisory board of the Millstein Center for Global Markets and Corporate Ownership at Columbia University where he has been a member since 2013 and has been the New York chairman of the Chairmen's Forum since 2011. He is board chairman of Lutheran Social Ministries of New Jersey, a charitable organization that provides adoption, assisted living, counseling, and immigration and refugee services, and is a former board member of PENCIL, a nonprofit organization that partners businesses with public schools.

The board concluded that Mr. McCracken should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. McCracken has extensive executive leadership experience and significant experience in information technology and cybersecurity through his tenure at CA, Inc. and IBM. This experience coupled with his service as the chair or a member of the board of other public companies and the NACD will enable him to provide insight into the operations, challenges, and complex issues our company is facing in today's environment and to make significant contributions to the board's oversight of operational risk management functions and corporate governance.

Patricia L. Moss

Age 62

Director Since 2003

Compensation Committee

Nominating and Governance Committee

Ms. Moss served as the president and chief executive officer of Cascade Bancorp, a financial holding company in Bend, Oregon, from 1998 to January 3, 2012. She served as the chief executive officer of Cascade Bancorp's principal subsidiary, Bank of the Cascades, from 1998 to January 3, 2012, serving also as president from 1998 to 2003. From 1987 to 1998, Ms. Moss served as chief operating officer, chief financial officer, and corporate secretary of Cascade Bancorp. Ms. Moss has been a director of Cascade Bancorp and Bank of the Cascades since 1993 and was elected vice chair of both boards effective January 3, 2012. Ms. Moss also serves as chair of the Bank of the Cascades Foundation Inc., co-chairs the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, and serves on the Board of Trustees for the Aquila Tax Free Trust of Oregon, a mutual fund created especially for the benefit of Oregon residents.

Ms. Moss graduated magna cum laude with a bachelor of science degree in business administration from Linfield College in Oregon and did master's studies at Portland State University. She received commercial banking school certification at the ABA Commercial Banking School at the University of Oklahoma. She served as a director of the Oregon Investment Fund Advisory Council, a state-sponsored program to encourage the growth of small businesses within Oregon; Oregon Business Council, whose mission is to mobilize business leaders to contribute to Oregon's quality of life and economic prosperity; the Cascades Campus Advisory Board of the Oregon State University; the North Pacific Group, Inc., a wholesale distributor of building materials, industrial and hardwood products, and other specialty products; Clear Choice Health Plans Inc., a multi-state insurance company; and the St. Charles Medical Center. She also served on the City of Bend's Juniper Ridge management advisory board.

The board concluded that Ms. Moss should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. A significant portion of MDU Resources Group, Inc.'s utility, construction services, and contracting operations are located in the Pacific Northwest. Ms. Moss has first-hand business experience and knowledge of the Pacific Northwest economy and local, state, and regional issues through her executive positions at Cascade Bancorp and Bank of the Cascades, where she gained over 30 years of experience. Ms. Moss provides to our board her experience in finance and banking, as well as her experience in business development through her work at Cascade Bancorp and on the Oregon Investment Fund Advisory Council, the Oregon Business Council, and the Oregon Growth Board. This business experience demonstrates her leadership abilities and success in the finance and banking industry. Ms. Moss has 18 years of experience as a certified senior professional in human resources, which makes her well-suited for our compensation committee.

Harry J. Pearce

Age 73

Director Since 1997

Chairman of the Board

Mr. Pearce was elected chairman of the board of the company on August 17, 2006. Prior to that, he served as lead director effective February 15, 2001, and was vice chairman of the board from November 16, 2000 until February 15, 2001. Mr. Pearce was a director and served on the audit, finance, compensation, and excellence committees of Marriott International, Inc., a major hotel chain, from 1995 to May 2015. He also was a director of Nortel Networks Corporation, a global telecommunications company, from January 11, 2005 to August 10, 2009, serving as chairman of the board from June 29, 2005. He retired on December 19, 2003, as chairman of Hughes Electronics Corporation, a General Motors Corporation subsidiary and provider of digital television entertainment, broadband satellite network, and global video and data broadcasting. He had served as a director of Hughes Electronics since 1992. Mr. Pearce was vice chairman and a director of General Motors Corporation, one of the world's largest automakers, from January 1, 1996 to May 31, 2001, and was general counsel from 1987 to 1994. He served on the President's Council on Sustainable Development and co-chaired the President's Commission on the United States Postal Service. Prior to joining General Motors, he was a senior partner in the Pearce & Durick law firm in Bismarck, North Dakota. Mr. Pearce is a director of the United States Air Force Academy Endowment and a trustee of Northwestern University. He is a Fellow of the American College of Trial Lawyers and a member of the International Society of Barristers. He has served as a chairman or director on the boards of numerous nonprofit organizations, including as chairman of the Board of Visitors of the U.S. Air Force Academy, chairman of the U.S. Air Force Academy Sabre Society, chairman of the National Defense University Foundation, and chairman of the Marrow Foundation. Mr. Pearce received a bachelor's degree in engineering sciences from the U.S. Air Force Academy and a juris doctor degree from Northwestern University's School of Law. He received an honorary degree of Doctor of Laws from Northwestern University and an honorary degree of Doctor of Engineering from Rose Hulman Institute of Technology.

The board concluded that Mr. Pearce should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. MDU Resources Group, Inc. values public company leadership and the experience directors gain through such leadership. Mr. Pearce is recognized nationally as a business leader and for his business acumen. He has multinational business management experience and proven leadership skills through his position as vice chairman at General Motors Corporation, as well as through his extensive service on the boards of large public companies, including Marriott International, Inc., Hughes Electronics Corporation, where he was chairman, and Nortel Networks Corporation, where he also was chairman. He also brings to our board his long experience as a practicing attorney. In addition, Mr. Pearce has focused on corporate governance issues and was the founding chair of Yale University's Chairmen's Forum, an organization comprised of non-executive chairmen of publicly traded companies. Participants in the Chairmen's Forum discussed ways to enhance the accountability of corporations to owners and promote a deeper understanding of independent board leadership and effective practices of board chairmanship. The board also believes that Mr. Pearce's values and commitment to excellence make him well-suited to serve as chairman of our board.

John K. Wilson

Age 61

Director Since 2003

Audit Committee

Mr. Wilson was president of Durham Resources, LLC, a privately held financial management company, in Omaha, Nebraska, from 1994 to December 31, 2008. He previously was president of Great Plains Energy Corp., a public utility holding company and an affiliate of Durham Resources, LLC, from 1994 to July 1, 2000. He was vice president of Great Plains Natural Gas Co., an affiliate company of Durham Resources, LLC, until July 1, 2000. The company bought Great Plains Energy Corp. and Great Plains Natural Gas Co. on July 1, 2000. Mr. Wilson also served as president of the Durham Foundation. He is presently a director of HDR, Inc., an international architecture and engineering firm; a director of Tetrad Corporation, a privately held investment company; and an executive director of the Robert B. Daugherty Foundation, all located in Omaha, Nebraska. Mr. Wilson formerly served as a director of Bridges Investment Fund, a mutual fund; a director of the Greater Omaha Chamber of Commerce; on the advisory board of U.S. Bank NA Omaha; and on the advisory board of Duncan Aviation, an aircraft service provider, headquartered in Lincoln, Nebraska.

Mr. Wilson is a certified public accountant, on inactive status. He received his bachelor's degree in business administration, cum laude, from the University of Nebraska – Omaha. During his career, he was an audit manager at Peat, Marwick, Mitchell (now known as KPMG), controller for Great Plains Natural Gas Co., and chief financial officer and treasurer for all Durham Resources entities.

The board concluded that Mr. Wilson should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. Wilson has an extensive background in finance and accounting, as well as extensive experience with mergers and acquisitions, through his education and work experience at a major accounting firm and his later positions as controller and vice president of Great Plains Natural Gas Co., president of Great Plains Energy Corp., and president, chief financial officer, and treasurer for Durham Resources, LLC and all Durham Resources entities. The electric and natural gas utility business was our core business when our company was founded in 1924. That business now operates through four utilities: Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company. Mr. Wilson is our only non-employee director with direct experience in this area through his prior positions at Great Plains Natural Gas Co. and Great Plains Energy Corp. In addition, Mr. Wilson's extensive finance and accounting experience make him well-suited for our audit committee.

The board of directors recommends a vote "for" each nominee.

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected and which we do not anticipate, directors will be elected by a plurality of the votes cast.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock "for" all directors nominated by the board of directors. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes "against" than votes "for" election at our annual meeting of stockholders and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee's recommendation no later than 90 days following the date of the annual meeting.

Brokers may not vote your shares on the election of directors if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.

ITEM 2. APPROVAL OF THE MATERIAL TERMS OF THE PERFORMANCE GOALS UNDER THE MDU RESOURCES GROUP, INC. LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN FOR PURPOSES OF INTERNAL REVENUE CODE SECTION 162(m)

The board of directors recommends that stockholders approve the material terms of the performance goals under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan to preserve our ability to deduct compensation associated with future performance-based incentive awards to be made under the plan.

Section 162(m) of the Internal Revenue Code of 1986, as amended, places a limit of $1,000,000 on the amount we may deduct in any one year for compensation paid to our "covered employees." A covered employee means a person specified in Section 162(m), which generally includes our chief executive officer and each of our other three most highly-compensated executive officers other than our chief financial officer.

There is an exception to this limit for certain performance-based compensation, and awards made pursuant to the plan may constitute performance-based compensation not subject to the deductibility limitation of Internal Revenue Code Section 162(m). To qualify for this exception, the stockholders must approve, every five years, the material terms of the performance goals of the plan under which compensation will be paid. Stockholders last approved the goals for the plan in 2011, and, therefore, the board is submitting the plan's performance goals for approval at the 2016 annual meeting of stockholders.

The board of directors amended the plan on November 12, 2015 to:

- include the following new performance goals: cash flow from operations (dollar target or as % of revenue), gross margin or gross profit (dollar target or as % of revenue), operations and maintenance expense (dollar target or as % of revenue), general and administrative expense (dollar target or as % of revenue), total operating expense (dollar target or as % of revenue), pretax income (dollar target or as % of revenue), earnings before interest, taxes, depreciation and amortization or "EBITDA" (dollar target or as % of revenue), earnings before interest and taxes or "EBIT" (dollar target or as % of revenue), earnings, return on invested capital, return on assets, return on net assets, working capital as percentage of revenue, days sales outstanding/accounts receivable turnover, and current ratio

- modify the operating income goal to: operating income (dollar target or as % of revenue)

- remove the following performance goals: oil and/or gas production (growth, value and costs) and oil and/or gas reserves (including proved, probable and possible reserves and growth, value and costs) and finding or development costs and

- add that performance goals may be measured on an individual basis and reflect individual performance or a relative comparison of individual performance.

The board of directors further amended the plan on February 11, 2016 to provide that if the company is required to prepare an accounting restatement due to material noncompliance with any financial reporting requirements under the securities laws, the company or the compensation committee may, or shall if required, take action to recover incentive-based compensation from specific executive officers in accordance with our Guidelines for Repayment of Incentives Due to Accounting Restatements, as they may be amended or substituted from time to time, and in accordance with applicable law and applicable rules of the Securities and Exchange Commission and the New York Stock Exchange.

The material terms of the performance goals are (i) eligibility and participation, (ii) the business criteria on which the performance goals are based, and (iii) maximum awards under the plan, which we describe further below.

Eligibility and Participation

All officers and key employees of the company and its subsidiaries, including employees who are members of the board, as determined by the compensation committee, are eligible to participate in the plan. The approximate number of employees who are currently eligible to participate in the plan is 40.

Performance Goals

The compensation committee establishes the performance goals, which will be based on one or more of the following measures: sales or revenues, earnings per share, shareholder return and/or value, funds from operations, cash flow from operations (dollar target or as % of revenue), gross margin or gross profit (dollar target or as % of revenue), operations and maintenance expense (dollar target or as % of revenue), general and administrative expense (dollar target or as % of revenue), total operating expense (dollar target or as % of revenue), operating income (dollar target or as % of revenue), pretax income (dollar target or as % of revenue), earnings before interest, taxes, depreciation and amortization or "EBITDA" (dollar target or as % of revenue), earnings before interest and taxes or "EBIT" (dollar target or as % of revenue), gross income, net income, cash flow, earnings, return on equity, return on invested capital, return on assets, return on net assets, working capital as percentage of revenue, days sales outstanding/accounts receivable turnover, current ratio, capital efficiency, operating ratios, stock price, enterprise value, company value, asset value growth, net asset value, shareholders' equity, dividends, customer satisfaction, accomplishment of mergers, acquisitions, dispositions or similar extraordinary business transactions, safety, sustainability, profit returns and margins, financial return ratios, and market performance. Performance goals may be measured solely on a corporate, subsidiary, business unit or individual basis, or a combination of the foregoing. Performance goals may reflect absolute entity or individual performance or a relative comparison of entity or individual performance to the performance of a peer group of entities or other external measure.

Maximum Awards under the Plan

Awards under the plan may be made in the form of restricted stock, performance units, performance shares, and any other type of award permitted under article 8 of the plan. The board of directors amended the plan on November 17, 2011 to remove stock options and stock appreciation grants from the types of awards that may be granted under the plan.

Subject to adjustment pursuant to the anti-dilution provisions in the plan, (i) the total number of shares of restricted stock intended to qualify as performance-based compensation that may be granted in any calendar year to any covered employee shall not exceed 2,250,000 shares, (ii) the total number of performance shares or performance units that may be granted in any calendar year to any covered employee shall not exceed 2,250,000 performance shares or performance units, as the case may be, (iii) the total number of shares that are intended to qualify as performance-based compensation granted pursuant to article 8 of the plan in any calendar year to any covered employee shall not exceed 2,250,000 shares, (iv) the total cash award that is intended to qualify as performance-based compensation that may be paid pursuant to article 8 of the plan in any calendar year to any covered employee shall not exceed $6,000,000, and (v) the aggregate number of dividend equivalents that are intended to qualify as performance-based compensation that a covered employee may receive in any calendar year shall not exceed $6,000,000.

The other material features of the plan are described below, and the complete text of the plan is attached to this proxy statement as Exhibit A.

Purpose of the Plan

The purpose of the plan is to promote the success and enhance the value of the company by linking the personal interests of officers and key employees to those of our stockholders and customers. The plan is further intended to provide flexibility in our ability to motivate, attract, and retain the services of participants upon whose judgment, interest, and special effort the successful conduct of our operations largely depends.

Effective Date and Duration

The plan was initially approved by the board of directors on February 7, 1997, and first became effective upon approval by stockholders at the annual meeting on April 22, 1997. The plan will remain in effect, subject to the right of the board of directors to terminate the plan at any time, until all shares subject to the plan have been issued.

Amendment, Modification, and Termination

The board may, at any time and from time to time, alter, amend, suspend, or terminate the plan, in whole or in part, provided that no amendment will be made without stockholder approval if the amendment would (i) increase the total number of shares that may be issued under the plan, (ii) materially modify the requirements for participation in the plan, or (iii) materially increase the benefits accruing to participants under the plan.

Administration of the Plan

The plan is administered by the compensation committee or by any other committee appointed by the board of directors. Subject to the terms of the plan, the committee has full power under the plan to determine persons to receive awards, the size and type of awards, and their terms. The committee may amend outstanding awards subject to restrictions stated in the plan.

Shares Subject to the Plan

When it originally became effective in 1997, the plan authorized the issuance of up to 1,200,000 shares of MDU Resources Group, Inc. common stock. In 2001, the stockholders approved an amendment to increase the number of shares that could be issued under the plan by 4,000,000 shares. On February 17, 2005, the Board of Directors amended the plan to reduce the number of shares that could be issued by 2,000,000 shares. As of February 11, 2016, after giving effect to stock splits and awards pursuant to the plan, 4,393,865 shares remain available for issuance under the plan, excluding 699,562 outstanding target level performance share awards granted in 2014, 2015, and 2016.

Shares underlying lapsed or forfeited restricted stock awards are not treated as having been issued under the plan. Shares withheld from an award to satisfy tax withholding obligations are counted as shares issued under the plan. Shares that are potentially deliverable under an award that expires or is canceled, forfeited, settled in cash, or otherwise settled without the delivery of shares are not treated as having been issued under the plan.

Shares issued under the plan may be authorized but unissued shares of common stock, treasury stock, or shares purchased on the open market.

In the event of any equity restructuring such as a stock dividend, stock split, spinoff, rights offering, or recapitalization through a large, nonrecurring cash dividend, the committee will cause an equitable adjustment to be made (i) in the number and kind of shares that may be delivered under the plan, (ii) in the individual limitations set forth in the plan, and (iii) with respect to outstanding awards, in the number and kind of shares subject to outstanding awards, price of shares subject to outstanding awards, any performance goals relating to shares, the market price of shares, or per-share results, and other terms and conditions of outstanding awards, in the case of (i), (ii), and (iii) to prevent dilution or enlargement of rights. In the event of any other change in corporate capitalization, such as a merger, consolidation, or liquidation, the committee may, in its sole discretion, cause an equitable adjustment as described in the foregoing sentence to be made, to prevent dilution or enlargement of rights. The number of shares subject to any award will always be rounded down to a whole number when adjustments are made pursuant to these provisions of the plan. Adjustments made by the committee pursuant to these provisions are final, binding, and conclusive.

Types of Awards under the Plan

Following is a general description of the types of awards that the compensation committee may make under the plan. The compensation committee will determine the terms and conditions of awards on a grant-by-grant basis, subject to limitations contained in the plan.

Restricted Stock. Restricted stock may be granted in such amounts and subject to such terms and conditions as determined by the committee, including time-based or performance-based vesting restrictions. The committee may establish performance goals, as described above, for restricted stock.

Participants holding restricted stock may exercise full voting rights with respect to those shares during the restricted period and, subject to the committee's right to determine otherwise at the time of grant, will receive regular cash dividends. All other distributions paid with respect to the restricted stock will be credited subject to the same restrictions on transferability and forfeitability as the shares of restricted stock with respect to which they were paid.

Performance Units and Performance Shares. Performance units and performance shares may be granted in the amounts and subject to such terms and conditions as determined by the committee. The committee will set performance goals, which, depending on the extent to which they are met during the performance periods established by the committee, will determine the number and/or value of performance units/shares that will be paid out to participants. Dividend equivalents may also be granted.

Participants will receive payment of the value of performance units/shares earned after the end of the performance period. Payment of performance units/shares will be made in cash and/or shares of common stock which have an aggregate fair market value equal to the value of the earned performance units/shares at the end of the applicable performance period, in such combination as the committee determines. Shares may be granted subject to any restrictions deemed appropriate by the committee.

Other Awards. The committee may make other awards which may include, without limitation, the grant of shares of common stock based upon attainment of performance goals established by the committee, the payment of shares in lieu of cash, the payment of cash based on attainment of performance goals, and the payment of shares in lieu of cash under our other incentive or bonus programs.

Minimum Vesting Requirements

Under the plan, the minimum vesting period for full value awards, which are awards pursuant to which shares may be issued that have no performance-based vesting characteristics, is three years. Vesting may occur ratably each month, quarter, or anniversary of the grant date. The minimum vesting period for full value awards with performance-based vesting characteristics is at least one year. The committee does not have discretion to accelerate vesting of full value awards except in the event of a change in control of the company or similar transaction, or the death, disability, or termination of employment of a participant. The committee may grant a "de minimis" number of full value awards that have a shorter vesting period. For this purpose, "de minimis" means 331,279 shares, subject to adjustment pursuant to the anti-dilution provisions in the plan.

Termination of Employment

Each award agreement will set forth the participant's rights with respect to each award following termination of employment.

Transferability

Except as otherwise determined by the committee and set forth in the award agreement and subject to the provisions of the plan, awards of restricted stock and performance units/performance shares may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution, and a participant's rights with respect to such shares or units shall be exercisable only by the participant or the participant's legal representative during his or her lifetime.

Change in Control

Upon a change in control, as defined below:

- any restriction periods and restrictions imposed on restricted stock or awards granted pursuant to article 8 of the plan, if not performance-based, will be deemed to have expired, and such restricted stock or awards will become immediately vested in full and

- the target payout opportunity attainable under all outstanding awards of performance units, performance shares, and other awards granted pursuant to article 8 of the plan, if performance-based, will be deemed to have been fully earned for the entire performance period(s) as of the effective date of the change in control and will be paid out promptly in shares or cash pursuant to the terms of the award agreement, or in the absence of such designation, as the committee shall determine.

The plan defines "change in control" as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock

- a change in a majority of our board of directors since April 22, 1997 without the approval of a majority of the board members as of April 22, 1997, or whose election was approved by such board members

- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors or

- stockholder approval of our liquidation or dissolution.

Accounting Restatements

The plan provides that if the company is required to prepare an accounting restatement due to material noncompliance with any financial reporting requirements under the securities laws, the company or the compensation committee may, or shall if required, take action to recover incentive-based compensation from specific executive officers in accordance with our Guidelines for Repayment of Incentives Due to Accounting Restatements, as they may be amended or substituted from time to time, and in accordance with applicable law and applicable rules of the Securities and Exchange Commission and the New York Stock Exchange.

Section 409A

To the extent applicable, it is intended that the plan and any awards made under the plan comply with the requirements of Internal Revenue Code Section 409A. Any provision that would cause the plan or any award to fail to satisfy Section 409A will have no force or effect until amended to comply with Section 409A, which amendment may be retroactive to the extent permitted by Section 409A.

Award Information

It is not possible at this time to determine awards that will be made in the future pursuant to the plan.

Equity Compensation Plan Information

The following table includes information as of December 31, 2015, with respect to our equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by stockholders [1]	565,896 [2]	— [3]	5,018,178 [4,5]
Equity compensation plans not approved by stockholders	N/A	N/A	N/A

[1] Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan, and the Non-Employee Director Stock Compensation Plan.

[2] Consists of performance shares.

[3] No weighted average exercise price is shown for the performance shares.

[4] 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of restricted stock, performance units, performance shares, or other equity-based awards. 4,585,932 shares remain available for future issuance under the Long-Term Performance-Based Incentive Plan in connection with grants of restricted stock, performance units, performance shares, or other equity-based awards.

[5] This amount also includes 74,489 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

The board of directors believes that it is in the best interests of the company and our stockholders to receive the full income tax deduction for performance-based compensation paid under the plan. The board is therefore asking the stockholders to approve, for purposes of Section 162(m), the material terms of the performance goals as set forth above. The plan will remain in effect if the stockholders do not approve the material terms of the performance goals, and failure to obtain stockholder approval will not affect the rights of participants under the plan or under any outstanding award agreements.

The board of directors recommends a vote "for" this proposal.

For purposes of Internal Revenue Code Section 162(m), approval requires a majority of the votes cast to be in favor of approval. Broker non-vote shares and abstentions will not count as votes cast.

ITEM 3. RATIFICATION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The audit committee at its February 2016 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2016. The board of directors concurred with the audit committee's decision. Deloitte & Touche LLP has served as our independent registered public accounting firm since fiscal year 2002.

Although your ratification vote will not affect the appointment or retention of Deloitte & Touche LLP for 2016, the audit committee will consider your vote in determining its appointment of our independent registered public accounting firm for the next fiscal year. The audit committee, in appointing our independent registered public accounting firm, reserves the right, in its sole discretion, to change an appointment at any time during a fiscal year if it determines that such a change would be in our best interests.

A representative of Deloitte & Touche LLP will be present at the annual meeting and will be available to respond to appropriate questions. We do not anticipate that the representative will make a prepared statement at the meeting; however, he or she will be free to do so if he or she chooses.

The board of directors recommends a vote "for" the ratification of Deloitte & Touche LLP as our independent registered public accounting firm for 2016.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2016 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal.

Accounting and Auditing Matters

Fees

The following table summarizes the aggregate fees that our independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill us for professional services rendered for 2015 and 2014:

	2015	2014 *
Audit Fees[a]	$ 2,755,400	$ 3,126,140
Audit-Related Fees[b]	437,979	45,925
Tax Fees[c]	36,400	24,300
All Other Fees[d]	47,569	100,527
Total Fees[e]	$ 3,277,348	$ 3,296,892
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	2.6 %	3.9 %

* The 2014 amounts were adjusted from amounts shown in the 2015 proxy statement to reflect actual amounts.

[a] Audit fees for 2015 and 2014 consisted of fees for services rendered for the audit of our annual financial statements, reviews of quarterly financial statements, subsidiary, statutory and regulatory audits, compliance with loan covenants, agreed upon procedures associated with the annual submission of financial assurance to the North Dakota Department of Health, the issuance of comfort letters relating to a sales agency agreement and offering of common stock (2014 only), filing Form S-3 and S-8 registration statements (2014 only), and the audit of financial statements for Fidelity Exploration & Production Company (2014 only). Audit fees for 2014 include $31,280 for the financial statement audit of Dakota Prairie Refining, LLC. These fees are paid by Dakota Prairie Refining, but are included in this table because Dakota Prairie Refining is considered a variable interest entity with respect to MDU Resources and consolidated in its financial statements.

[b] Audit-related fees for 2015 and 2014 are associated with accounting research assistance, agreed upon procedures associated report for Knife River Corporation's JTL Group, Inc. (Wyoming) (2015 only), due diligence work associated with a potential acquisition (2015 only), and technical accounting consultation regarding discontinued and continuing operations (2014 only).

[c] Tax fees for 2015 and 2014 include the preparation of federal and state tax returns for Dakota Prairie Refining, LLC. The fees associated with Dakota Prairie Refining are paid by Dakota Prairie Refining, but are included in this table because Dakota Prairie Refining is considered a variable interest entity with respect to MDU Resources and is consolidated in its financial statements.

[d] All other fees for 2015 and 2014 are associated with a cost segregation study and research on R&D credits, in each case for Dakota Prairie Refining, LLC. The fees associated with Dakota Prairie Refining are paid by Dakota Prairie Refining, but are included in this table because Dakota Prairie Refining is considered a variable interest entity with respect to MDU Resources and consolidated in its financial statements.

[e] Total fees reported above include out-of-pocket expenses related to the services provided of $382,965 for 2015 and $420,732 for 2014.

Pre-Approval Policy

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2015 in accordance with the pre-approval policy and procedures the audit committee adopted at its August 12, 2003 meeting. This policy is designed to achieve the continued independence of Deloitte & Touche LLP and to assist in our compliance with Sections 201 and 202 of the Sarbanes-Oxley Act of 2002 and related rules of the Securities and Exchange Commission.

The policy defines the permitted services in each of the audit, audit-related, tax, and all other services categories, as well as prohibited services. The pre-approval policy requires management to submit annually for approval to the audit committee a service plan describing the scope of work and anticipated cost associated with each category of service. At each regular audit committee meeting, management reports on services performed by Deloitte & Touche LLP and the fees paid or accrued through the end of the quarter preceding the meeting. Management may submit requests for additional permitted services before the next scheduled audit committee meeting to the designated member of the audit committee, Dennis W. Johnson, for approval. The designated member updates the audit committee at the next regularly scheduled meeting regarding any services that he approved during the interim period. At each regular audit committee meeting, management may submit to the audit committee for approval a supplement to the service plan containing any request for additional permitted services.

In addition, prior to approving any request for audit-related, tax, or all other services of more than $50,000, Deloitte & Touche LLP will provide a statement setting forth the reasons why rendering of the proposed services does not compromise Deloitte & Touche LLP's independence. This description and statement by Deloitte & Touche LLP may be incorporated into the service plan or included as an exhibit thereto or may be delivered in a separate written statement.

ITEM 4. APPROVAL, ON A NON-BINDING ADVISORY BASIS, OF THE COMPENSATION OF THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(a), we are asking our stockholders to approve, in a separate advisory vote, the compensation of our named executive officers as disclosed in this proxy statement pursuant to Item 402 of Regulation S-K. As discussed in the Compensation Discussion and Analysis, our compensation committee and board of directors believe that our current executive compensation program directly links compensation of our named executive officers to our financial performance and aligns the interests of our named executive officers with those of our stockholders. Our compensation committee and board of directors also believe that our executive compensation program provides our named executive officers with a balanced compensation package that includes an appropriate base salary along with competitive annual and long-term incentive compensation targets. These incentive programs are designed to reward our named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy is built on a foundation of these guiding principles:

- we pay for performance, with over 50% of our 2015 total target direct compensation for our named executive officers in the form of incentive compensation
- we assess the relationship between our named executive officers' pay and performance on key financial metrics - revenue, profit, return on invested capital, and stockholder return - in comparison to our performance graph peer group
- we review competitive compensation data for our named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels
- we determine annual performance incentives based on financial criteria that are important to stockholder value, including earnings, earnings per share, and return on invested capital and
- we determine long-term performance incentives based on total stockholder return relative to our performance graph peer group.

We are asking our stockholders to indicate their approval of our named executive officer compensation as disclosed in this proxy statement, including the Compensation Discussion and Analysis, the executive compensation tables, and narrative discussion. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers for 2015. Accordingly, the following resolution is submitted for stockholder vote at the 2016 annual meeting:

> "RESOLVED, that the compensation paid to the company's named executive officers, as disclosed pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables, and narrative discussion of this proxy statement, is hereby approved."

As this is an advisory vote, the results will not be binding on the company, the board of directors, or the compensation committee and will not require us to take any action. The final decision on the compensation of our named executive officers remains with our compensation committee and our board of directors, although our board and compensation committee will consider the outcome of this vote when making future compensation decisions. As the board of directors determined at its meeting in May 2011, we will provide our stockholders with the opportunity to vote on our named executive officer compensation at every annual meeting until the next required vote on the frequency of stockholder votes on named executive officer compensation. The next required vote on frequency will occur at the 2017 annual meeting of stockholders.

The board of directors recommends a vote "for" the approval, on a non-binding advisory basis, of the compensation of our named executive officers, as disclosed in this proxy statement.

Approval of the compensation of our named executive officers requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal. Broker non-vote shares are not entitled to vote on this proposal and, therefore, are not counted in the vote.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis may contain statements regarding corporate performance targets and goals. These targets and goals are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance. We specifically caution investors not to apply these statements to other contexts.

Executive Summary

Named Executive Officers

Our named executive officers for 2015 were:

- David L. Goodin, president and chief executive officer of MDU Resources Group, Inc.
- Doran N. Schwartz, vice president and chief financial officer
- David C. Barney, president and chief executive officer of our construction materials and contracting segment, Knife River Corporation; Mr. Barney was not a named executive officer in 2014
- Jeffrey S. Thiede, president and chief executive officer of our construction services business segment, MDU Construction Services Group, Inc.
- Patrick L. O'Bryan, president and chief executive officer of our exploration and production business segment, Fidelity Exploration & Production Company; Mr. O'Bryan was not a named executive officer in 2014. Substantially all of the assets of Fidelity were sold during 2015, and it is no longer considered a business segment. Mr. O'Bryan resigned his position effective February 29, 2016, and
- Steven L. Bietz, former president and chief executive officer of our pipeline and energy services segment, WBI Holdings, Inc., which is the parent company of WBI Energy, Inc. and WBI Energy Services, Inc.; Mr. Bietz retired effective July 17, 2015.

Key Financial Results for 2015

Consolidated GAAP earnings in 2015 were $(623.1) million, or $(3.20) per share, compared to earnings of $297.5 million, or $1.55 per share, in 2014.

Our total stockholder return for 2015 was (19.0)%, as compared to (21.2)% for 2014. Our average annual total stockholder return for the five-year period ended December 31, 2015 was 1.0%, compared to 2.8% for the five-year period ended December 31, 2014.

Total Realized Pay Compared to Total Compensation from the Summary Compensation Table

The compensation committee believes total realized pay, the actual remuneration received by the named executive, is equally as important as total compensation as presented in the Summary Compensation Table. Total realized pay reflects the compensation actually earned, which can differ substantially from total compensation as presented in the Summary Compensation Table.

Total compensation as presented in the Summary Compensation Table contains estimated values of grants of performance shares based on multiple assumptions that may or may not come to fruition. Total realized pay does not include the value of performance shares at grant but rather includes their value only if they vest and then at the level they are actually earned. The Summary Compensation Table also shows any increase in pension value, which may result in large part from changes in the valuation assumptions and discount rates used for calculation. Total realized pay excludes the change in pension value and above-market earnings on nonqualified deferred compensation because:

- an increase in pension value can result in a much higher number reported as total compensation in the Summary Compensation Table
- when pension value decreases, as it did for 2015 due to the use of a higher discount rate, the negative value does not reduce total compensation as reported in the Summary Compensation Table and
- Supplemental Income Security Plan benefits depend partially on continued employment for some of the named executive officers.

We define total realized pay as the sum of:

- base salary
- annual incentive awards and bonus paid with respect to the year
- the value realized upon the vesting of long-term incentive awards of performance shares during the year and
- all other compensation as reported in the Summary Compensation Table.

The following table compares total realized pay for our named executives in 2015 to the total compensation as presented in the Summary Compensation Table. This table is not intended to be a substitute for the Summary Compensation Table.

Named Executive Officer	Base Salary ($)	Annual Incentive Awards and Bonus Paid ($)	Value Realized upon Vesting of Performance Shares ($)[1]	All Other Compensation ($)	Total Realized Pay ($)	Total Compensation from the Summary Compensation Table ($)
David L. Goodin	755,000	376,745	—	39,411	1,171,156	2,558,148
Doran N. Schwartz	380,000	123,253	—	35,571	538,824	818,052
David C. Barney	395,000	637,588	—	22,556	1,055,144	1,290,413
Jeffrey S. Thiede	425,000	161,857	—	172,506	759,363	1,002,265
Patrick L. O'Bryan[2]	441,918	1,359,425	—	21,356	1,822,699	1,822,699
Steven L. Bietz[3]	214,274	—	—	787,351	1,001,625	1,307,120

[1] Performance shares and dividend equivalents for the 2012-2014 performance period did not vest and were forfeited because performance was below threshold.

[2] Promoted effective March 1, 2015; his base salary is prorated.

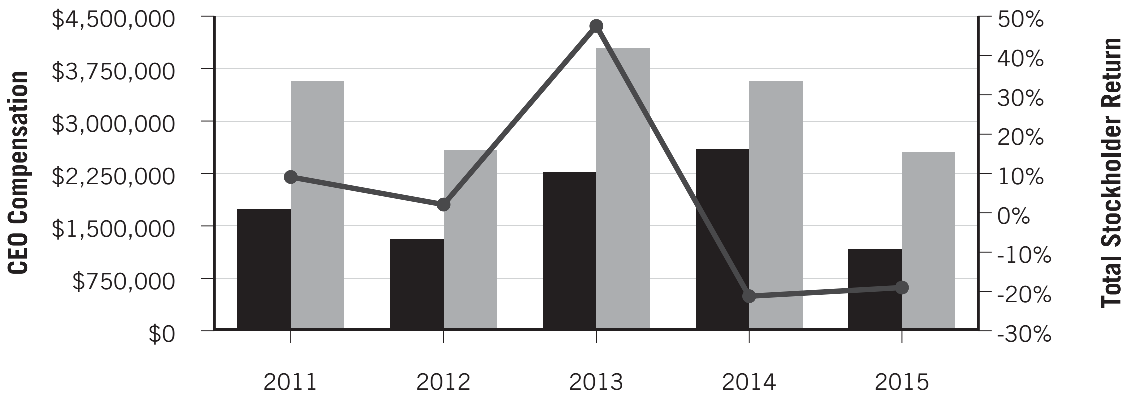
[3] Retired effective July 17, 2015; his base salary is prorated.

With respect to our chief executive officer, the following table demonstrates our pay for performance approach for 2011 through 2015 by comparing:

- total realized pay, which is the sum of base salary, annual incentive awards paid, all other compensation, and the value realized upon the vesting of performance shares during 2014 (for the 2011 through 2013 performance cycle). None vested during 2011, 2012, 2013, or 2015.
- total compensation as reported in the Summary Compensation Table and
- one-year total stockholder returns for 2011 through 2015.

For years 2011 and 2012, the compensation information is for Mr. Hildestad, our chief executive officer for those years, and for 2013 through 2015, the compensation information is for Mr. Goodin. This table is not intended to be a substitute for the Summary Compensation Table.

5 Year CEO Compensation and Total Stockholder Return



	2011	2012	2013	2014	2015
Total Realized Pay	$1,742,249	$1,306,474	$2,273,142	$2,601,803	$1,171,156
Total Compensation from Summary Compensation Table	$3,566,327	$2,558,778	$4,047,413	$3,571,637	$2,558,148
1 Year Total Stockholder Return	9.1%	2.1%	47.5%	(21.2)%	(19.0)%

In 2015, when our total stockholder return was (19.0)%, our chief executive officer's total realized pay decreased $1.4 million, or 55%, and his total compensation from the Summary Compensation Table decreased $1.0 million, or 28%.

The decrease in Mr. Goodin's total realized pay was due primarily to the nonvesting of performance shares and dividend equivalents for the 2012-2014 performance cycle, where our total stockholder return was below threshold compared to our performance graph peer group. The decrease in Mr. Goodin's total compensation from the Summary Compensation Table was due primarily to a decrease in the change in pension value and lower realized annual incentive compensation.

Process for Determination of 2015 Compensation

Objectives of our Compensation Program

We have a written executive compensation policy for our Section 16 officers, including all our named executive officers. Our policy's stated objectives are to:

- recruit, motivate, reward, and retain high performing executive talent required to create superior long-term total stockholder return in comparison to our peer group
- reward executives for short-term performance, as well as the growth in enterprise value over the long-term
- provide a competitive package relative to industry-specific and general industry comparisons and internal equity, as appropriate
- ensure effective utilization and development of talent by working in concert with other management processes - for example, performance appraisal, succession planning, and management development and
- help ensure that compensation programs do not encourage or reward excessive or imprudent risk taking.

Role of Compensation Consultants

Our executive compensation policy calls for an assessment of the competitive pay levels for base salary and incentive compensation for each Section 16 officer position to be conducted at least every two years by an independent consulting firm. For 2015 compensation, the compensation committee retained Towers Watson, a nationally recognized consulting firm, to perform this assessment and to assist the compensation committee in establishing competitive compensation targets for our Section 16 officers.

The compensation committee asked Towers Watson to prepare separate executive compensation reviews for the Section 16 officers and for the chief executive officer. In its review for the Section 16 officers, Towers Watson was asked to:

- match the Section 16 officer positions to survey data to generate 2015 market estimates for base salaries and short-term and long-term incentives
- address general trends in executive compensation
- compare base salaries and target short-term and long-term incentives, by position, to market estimates and recommend salary grade changes as appropriate
- compare Section 16 officer pay to the chief executive officer pay
- construct a recommended 2015 salary grade structure and
- verify the competitiveness of short-term and long-term incentive targets associated with salary grades and recommend modifications as appropriate.

In the chief executive officer review, Towers Watson was asked to use survey data and data from the company's performance graph peer group to:

- compare and develop competitive estimates for base salary and target short-term and long-term incentives
- recommend changes in base salary and incentives targets based on competitive data and
- address general trends in chief executive officer compensation.

Towers Watson also prepared pay equity competitive information, comparing the chief executive officer's pay as a multiple of the company's top executives to the performance graph peer group.

The compensation surveys used in the competitive assessment are listed on the following table:

Survey*	Number of Companies Participating (#)	Median Number of Employees (#)	Number of Publicly Traded Companies (#)	Median Revenue (000s) ($)
Towers Watson 2013 CDB General Industry Executive Database	442	18,400	376	6,376,000
Towers Watson 2013 CSR Report on Top Management Compensation	480	4,550	178	1,396,700
Towers Watson 2013 CDB Energy Services Executive Database	104	2,721	76	2,713,000
Mercer 2013 Total Compensation Survey for the Energy Sector	352	Not Reported	273	957,000

* The information in the table is based solely upon information provided by the publishers of the surveys and is not deemed filed or a part of this Compensation Discussion and Analysis for certification purposes. For a list of companies that participated in the compensation surveys and databases, see Exhibit B.

In billions of dollars, our revenues from continuing operations for 2013, 2014, and 2015 were approximately $3.9, $4.1, and $4.2, respectively.

Role of Management

Mr. Goodin played an important role in recommending 2015 compensation to the committee for the other named executive officers. Mr. Goodin assessed the performance of the named executive officers and considered the relative value of the named executive officers' positions and their salary grade classifications. He then reviewed the competitive assessment prepared by Towers Watson to formulate 2015 compensation recommendations, other than for himself. He also recommended compensation for Mr. O'Bryan in connection with his promotion in 2015 and a sales bonus in connection with the sale of Fidelity, an additional incentive for Mr. Barney, and a severance payment for Mr. Bietz in connection with his retirement. Mr. Goodin attended compensation committee meetings; however, he was not present during discussions regarding his compensation.

Performance Assessment Program

Our performance assessment program rates performance of our executive officers, except for our chief executive officer, in the following areas, which help determine actual salaries within the range of salaries associated with the executive's salary grade:

- leadership
- leading with integrity
- achievement focus
- risk management
- mentoring
- financial responsibility
- safety

An executive's overall performance in our performance assessment program is rated on a scale of one to five, with five as the highest rating denoting distinguished performance. An overall performance above 3.75 is considered commendable performance.

Peer Group

In addition to the survey data provided by the compensation consultant, the compensation committee reviews compensation data from our performance graph peer group in assessing the level of base salary and the target level of annual incentive awards and long-term incentive awards for some of our named executive officers. The companies comprising the 2014 performance graph peer group, which was used in assessing compensation for 2015, were:

- ALLETE, Inc.
- Alliant Energy Corporation
- Atmos Energy Corporation
- Avista Corporation
- Bill Barrett Corporation
- Black Hills Corporation
- Comstock Resources, Inc.
- EMCOR Group, Inc.
- EQT Corporation
- Granite Construction Incorporated
- Martin Marietta Materials, Inc.
- National Fuel Gas Company
- Northwest Natural Gas Company
- Pike Corporation
- Quanta Services, Inc.
- Questar Corporation
- SM Energy Company
- Sterling Construction Company, Inc.
- Swift Energy Company
- Texas Industries
- Vectren Corporation
- Vulcan Materials Company
- Whiting Petroleum Corporation

The compensation committee also used the performance graph peer group companies in connection with performance share awards under the Long-Term Performance-Based Incentive Plan, where the company's relative stockholder return is compared to the performance graph peer group. Please see the discussion under 2015 Long-Term Incentives, Performance Share Awards, for the names of the companies comprising the performance graph peer group when the committee granted performance share awards in February 2015.

Salary Grades for 2015

The compensation committee determines the named executive officers' base salaries and target annual and long-term incentives by reference to salary grades. Each salary grade has a minimum, midpoint, and maximum annual salary level with the midpoint targeted at approximately the 50th percentile of the competitive assessment data for positions in the salary grade. The compensation committee may adjust the salary grades away from the 50th percentile in order to balance the external market data with internal equity. The salary grades also have target annual and long-term incentive levels, which are expressed as a percentage of the individual's base salary. We generally place named executive officers into a salary grade based on historical classification of their positions; however, the compensation committee reviews each classification and may place a position into a different salary grade if it determines that the targeted competitive compensation for the position changes significantly or the executive's responsibilities and/or performance warrants a different salary grade. Individual executives may be paid below, equal to, or above the salary grade midpoint.

The salary grades give the compensation committee flexibility to assign different salaries to individual executives within a salary grade to reflect one or more of the following:

- executive's performance on financial goals and on non-financial goals, including the results of the performance assessment program
- executive's experience, tenure, and future potential
- position's relative value compared to other positions within the company
- relationship of the salary to the competitive salary market value
- internal equity with other executives and
- economic environment of the corporation or executive's business segment.

The committee increased the 2015 base salary grade midpoints for salary grades A through K by a total of 2.2% to more closely align with the 50th percentile of the competitive assessment data. The midpoint of salary grade L, which is Mr. Goodin's salary grade, was increased by 2.6% from $780,000 to $800,000; and the midpoint of salary grade J, which is the salary grade for Messrs. Schwartz, Barney, Thiede, O'Bryan, and Bietz, was increased by 2.6% from $390,000 to $400,000.

The committee moved Mr. Schwartz from salary grade I to salary grade J to more closely align with the Towers Watson survey data and the performance graph peer group companies, which showed median base salaries for chief financial officers of $500,000 and $405,000, respectively. Mr. O'Bryan's salary grade was changed from I to J, the salary grade for the business segment heads, in connection with his promotion to president and chief executive officer of Fidelity Exploration & Production Company, effective March 1, 2015.

For salary grade L, the committee decreased the target annual incentive from 150% to 100% of base salary, based on the competitive data which showed that 150% was at the high end of the range. The committee also increased the target long-term incentive for salary grade L from 150% to 225% of base salary, which is more in line with market norms. The committee kept the 2015 target annual and long-term incentive compensation guidelines for salary grade J at 65% and 90%, respectively, of base salary.

Our named executive officers' 2015 salary grade classifications and their respective midpoints are:

Position	Grade	Name	2015 Salary Grade Base Salary Midpoint ($000s)
President and CEO	L	David L. Goodin	800
Vice President and CFO	J	Doran N. Schwartz	400
President and CEO, Knife River Corporation	J	David C. Barney	400
President and CEO, MDU Construction Services Group, Inc.	J	Jeffrey S. Thiede	400
President and CEO, Fidelity Exploration & Production Company	J	Patrick L. O'Bryan	400
President and CEO, WBI Holdings, Inc.	J	Steven L. Bietz	400

Timing of Compensation Decisions for 2015

The compensation committee, in conjunction with the board of directors, determined all compensation for each named executive officer for 2015. The compensation committee made recommendations to the board of directors regarding compensation of all Section 16 officers, and the board of directors then approved the recommendations.

The compensation committee reviewed the competitive assessment at its August 2014 and November 2014 meetings. At the November 2014 meeting, it established individual base salaries, target annual incentive award levels, and target long-term incentive award levels for 2015 for most of the named executive officers. Mr. Goodin's target incentive target award levels were reviewed and established at the February 2015 meeting. In conjunction with his promotion, Mr. O'Bryan's 2015 compensation was determined at the February and May 2015 meetings. At the February 2015 meeting, the compensation committee and the board of directors determined 2015 annual and long-term incentive awards, along with payments based on performance for the 2014 annual incentive awards. No payments were made for the 2012-2014 performance share awards. The February meeting occurred after the release of earnings for the prior year. Mr. Bietz's additional payment in connection with his retirement was determined at the June 2015 compensation committee and board meetings.

Stockholder Advisory Vote ("Say on Pay")

Our stockholders had an advisory vote on our named executive officers' 2014 compensation at the 2015 Annual Meeting of Stockholders. Approximately 88% of the shares present in person or represented by proxy and entitled to vote on the matter approved the named executive officers' compensation. The 88% approval is lower than the results of our say on pay vote at the 2014 Annual Meeting, which was 97%. While the compensation committee did not change compensation for 2015 as a result of the vote, the committee considered the results of the vote at their May 2015, August 2015, and November 2015 meetings in connection with setting compensation for 2016, requesting the vice president-human resources to prepare an analysis of the industry competitiveness of the company's annual and long-term incentive awards, including the degree of stretch in the goals, the mix of annual and long-term incentive compensation, and the use of total stockholder return as a single measure for the long-term incentive awards.

Allocation of Total Target Compensation for 2015

Incentive compensation, which consists of annual cash incentive awards and three-year performance share awards under our Long-Term Performance-Based Incentive Plan, comprises a significant portion of our named executive officers' total target compensation because:

- our named executive officers are in positions to drive, and therefore bear high levels of responsibility for, our corporate performance
- incentive compensation is more variable than base salary and dependent upon our performance
- variable compensation helps ensure focus on the goals that are aligned with our overall strategy and
- the interests of our named executive officers will be aligned with those of our stockholders by making a significant portion of their target compensation contingent upon results that are beneficial to stockholders.

The following table shows the allocation of total target compensation for 2015 among the individual components of base salary, annual incentive (including the additional annual incentives granted to Mr. Barney and Mr. O'Bryan), and long-term incentive:

Name	% of Total Target Compensation Allocated to Base Salary (%)	% of Total Target Compensation Allocated to Incentives		
		Annual (%)	Long-Term (%)	Annual + Long-Term (%)
David L. Goodin	23.5	23.5	53.0	76.5
Doran N. Schwartz	39.2	25.5	35.3	60.8
David C. Barney	34.7	41.0	24.3	65.3
Jeffrey S. Thiede	40.0	32.0	28.0	60.0
Patrick L. O'Bryan	20.0	80.0	—	80.0
Steven L. Bietz	39.2	25.5	35.3	60.8

In order to reward long-term growth, the compensation committee generally allocates a higher percentage of total target compensation to the long-term incentive than to the annual incentive for our higher level executives, since they are in a better position to influence our long-term performance. The long-term incentive, if earned, is paid in company common stock. These awards, combined with our stock retention requirements and stock ownership policy, discussed later, promote ownership of our stock by the named executive officers. The compensation committee believes that, as stockholders, the named executive officers will be motivated to deliver financial results that build wealth for all stockholders over the long-term.

Messrs. Barney's and Thiede's long-term incentive percentage continued to be lower than their annual incentive percentage, as they transition from all annual incentive to a combination of annual and long-term incentive in connection with their promotions in 2013. Mr. Barney also received an additional annual incentive award in February 2015, which further increased the annual incentive portion of his total target compensation. Mr. O'Bryan did not receive a long-term incentive award in 2015, reflecting the company's potential marketing of Fidelity, with any sale likely to occur before the conclusion of the three-year performance period.

PEER Analysis: Comparison of Pay for Performance Ratios

Each year we compare our named executive officers' pay for performance ratios to the pay for performance ratios of the named executive officers in the performance graph peer group. This analysis compares the relationship between our compensation levels and our average annual total stockholder return to the peer group over a specified period. In 2015 we looked at two separate five-year periods: 2009-2013 and 2010-2014 and two separate three-year periods: 2011-2013 and 2012-2014. All data used in the analysis, including the valuation of long-term incentives and calculation of stockholder return, were compiled by Equilar, Inc., an independent service provider, based on each company's annual filings for its data collection.

This analysis consisted of dividing what we paid our named executive officers for the period by our average annual total stockholder return for the same period to yield our pay ratio. For this comparison, we used the 2015 performance graph peer group companies. Our pay ratio was then compared to the pay ratio of the companies in the performance graph peer group, which was calculated by dividing total direct compensation for all the peer group executives by the sum of each company's average annual total stockholder return for the same period. The average annual stockholder return is the geometric mean for the period.

For the five-year period 2009 through 2013, we paid our named executives approximately $4.9 million per point of shareholder return, while the peer group companies paid their named executives approximately $4.1 million per point of shareholder return. For the five-year period 2010 through 2014, we paid our named executives approximately $15.8 million per point of shareholder return, reflecting a large decrease in our total stockholder return, while the peer group companies paid their named executives approximately $5.6 million per point of shareholder return. The three-year periods resulted in a comparison of $1.7 million for the company versus $2.4 million for the peer group for 2011-2013 and a comparison of $4.8 million for the company versus $1.9 million for the peer group for 2012-2014. The compensation committee believes that the analysis continues to serve a useful purpose in its annual review of compensation for the named executives.

2015 Compensation for Our Named Executive Officers

Base Salaries, Total Annual Compensation, and Total Direct Compensation

David L. Goodin
For 2015, the compensation committee gave Mr. Goodin, our president and chief executive officer, a 10.2% increase, raising his salary from $685,000 to $755,000, or 94% of the midpoint of salary grade L. The committee noted that the $755,000 was above the median salary of $726,000 for the chief executive officers from the performance graph peer companies and below the market average salary of $910,000 for the chief executive officers from the salary survey data, both as noted in the competitive assessment. The committee believed the 10.2% increase was appropriate in recognition of favorable return on invested capital results compared to the performance graph peers for the twelve months ended June 30, 2014 and results on succession planning and leadership development. The committee also believed it was appropriate to move Mr. Goodin's 2015 base salary closer to the competitive reference point. The committee established Mr. Goodin's 2015 target total annual cash compensation at $1,510,000, a reduction from his 2014 target of $1,712,500. Mr. Goodin's 2015 target total annual cash was above the median total cash compensation of $1,385,000 paid to chief executive officers from the performance graph peer companies and below the median total cash compensation of $1,865,000 paid to chief executive officers from the salary survey data, both as noted in the competitive assessment. From a total direct compensation perspective, the committee established a target of $3,208,750, which was aligned with the competitive reference point of $3,291,000 for the performance graph peer group and below the competitive reference point of $4,665,000 for the salary survey companies.

Doran N. Schwartz
As discussed above, the committee changed the salary grade of Mr. Schwartz, our vice president and chief financial officer, from I to J and increased his base salary 5.6%, from $360,000 to $380,000, or 95% of the midpoint of salary grade J. Combined with his target annual and long-term incentive, this would result in target total annual compensation of 70.1% and target total direct compensation of 60.4% of the competitive market data at the 50th percentile. The compensation committee's rationale for the increase was in recognition of his:

- leadership positions in the sale of company common stock under the at-the-market equity program, debt financings for the company and financings for the Dakota Prairie Refinery and
- relatively low salary compared to the chief financial officers of performance graph peer companies.

David C. Barney
For 2015, the compensation committee gave Mr. Barney, president and chief executive officer of Knife River Corporation, a 3.9% increase in base salary, raising his salary from $380,000 to $395,000 or 99% of the midpoint of salary grade J. Combined with his target annual and long-term incentives, along with an additional annual incentive (cash flow), this would result in target total annual compensation of 121.3% and target total direct compensation of 93.2% of the competitive salary survey data at the 50th percentile. The compensation committee's rationale for the increase was in recognition of:

- his results in managing Knife River Corporation, moving it closer to meeting or exceeding its weighted average cost of capital
- his credible leadership and
- his respect by Knife River Corporation employees.

Jeffrey S. Thiede
For 2015, the compensation committee gave Mr. Thiede, president and chief executive officer of MDU Construction Services Group, Inc., a 6.3% increase in base salary, raising his annual salary from $400,000 to $425,000, or 106% of the midpoint of salary grade J. Combined with his target annual and long-term incentives, this would result in target total annual compensation of 115.9% and target total direct compensation of 95.7% of the competitive salary survey data at the 50th percentile. The committee believed the 6.3% salary increase was appropriate in recognition of his strong leadership and continued delivery of outstanding results and the accomplishments in unifying MDU Construction Services Group, Inc. under his leadership.

Patrick L. O'Bryan
In establishing Mr. O'Bryan's compensation, the committee reviewed the pay arrangements of chief operating officers of publicly traded companies with revenues of $250 million to $1.5 billion in four SIC codes in the oil and gas business, as compiled by Equilar. These companies are listed in Exhibit B. The committee changed Mr. O'Bryan's salary grade from I to J and increased his salary from $400,000 to $450,000, effective March 1, 2015, in connection with his promotion to president and chief executive officer of Fidelity Exploration & Production Company. His salary was set at 112.5% of the midpoint of salary grade J. Combined with his target annual incentive and his two additional annual incentives (retention and sales bonus incentives), this would result in target total compensation of $2.24 million or 140.1% of total target direct compensation of $1.6 million as shown in the Equilar data. The committee believed that Mr. O'Bryan's involvement in the Fidelity sales process would likely bring significant incremental value and recognized the importance of keeping Mr. O'Bryan incentivized to remain with the company and lead a successful sales effort.

Steven L. Bietz
For 2015, the compensation committee gave Mr. Bietz, president and chief executive officer of WBI Holdings, Inc. until his retirement in July 2015, a 3.9% increase, raising his salary from $380,000 to $395,000, or 99% of the midpoint of salary grade J. Combined with his target annual and long-term incentives, this would result in target total annual compensation of 100.3% and target total direct compensation of 91.6% of the competitive salary survey data at the 50th percentile. The compensation committee's rationale for the increase was in recognition of the earnings growth at WBI Energy, Inc. under Mr. Bietz's leadership.

Annual Incentives

2015 Annual Incentives
The committee granted regular annual incentives to the executive officers in February 2015, as it has in prior years, and also during 2015 granted or approved additional annual incentives for Mr. Barney and Mr. O'Bryan. In the following sections, we discuss the regular annual incentives, with the additional incentives discussed separately under "Additional Annual Incentives."

What the Performance Measures Are and Why We Chose Them
The compensation committee develops and reviews financial and other corporate performance measures to help ensure that compensation to the executives reflects the success of their respective business segment and/or the corporation, as well as the value provided to our stockholders.

The compensation committee believes earnings, earnings per share, and return on invested capital are very good measurements in assessing a business segment's performance and the company's performance from a financial perspective, because:

- earnings and earnings per share are generally accepted accounting principle measurements and are key drivers of stockholder return over the long-term and
- return on invested capital measures how efficiently and effectively management deploys capital, where sustained returns on invested capital in excess of a business segment's cost of capital create value for our stockholders.

As in prior years, the compensation committee selected allocated earnings per share and return on invested capital for the pipeline and energy services segment, the electric and natural gas distribution segments, and the construction materials and contracting segment to ensure those chief executive officers' annual incentive payments are closely aligned to criteria promoting long-term growth in stockholder return. We establish these targets in connection with our annual financial planning process, where we assess the economic environment, competitive outlook, industry trends, and company specific conditions to set projections of results. The compensation committee evaluates the projected results and uses this evaluation to establish the incentive plan performance targets based upon recommendations of the chief executive officer. Allocated earnings per share for a business segment is calculated by dividing that business segment's earnings by the business segment's portion of the total company weighted average shares outstanding. Return on invested capital for a business segment is calculated by dividing the business segment's earnings, without regard to after tax interest expense and preferred stock dividends, by the business segment's average capitalization for the calendar year. If the compensation committee utilizes a return on invested capital target for a business segment, it considers the business segment's weighted average cost of capital. The weighted average cost of capital is a composite cost of equity and debt used to finance a company's assets. It is calculated by averaging the cost of debt plus the cost of equity by the proportion each represents in the business segment's capital structure.

The compensation committee continued to use earnings as the performance measure for the construction services segment, with selected earnings levels chosen to balance conservative financial planning, as well as earnings volatility for that segment. For the exploration and production segment, pretax operating income, excluding depletion, depreciation and amortization, and margin enhancement, defined as operations and maintenance expense, which the committee viewed as directly related to driving value at this segment, were used as performance measures.

For the named executive officers working at MDU Resources Group, Inc., who were Messrs. Goodin and Schwartz, the compensation committee continued to base annual incentives on the achievement of performance goals at the business segments: (i) the construction materials and contracting segment, (ii) the construction services segment, (iii) the pipeline and energy services segment, (iv) the exploration and production segment, and (v) the electric and natural gas distribution segments. The compensation committee's rationale for this approach was to provide greater alignment between the MDU Resources Group, Inc. executives and business segment performance.

As established by the compensation committee in February 2015, the annual performance measures and goal weightings for the business segment leaders were:

		Business Segment Goal Weighting					Company Goal Weighting	
Position	Business Segment	Allocated EPS (%)	ROIC (%)	Earnings (%)	Pretax Operating Income (%)[1]	Margin Enhancement (%)[2]	EPS (%)[3]	E&P Segment Pretax Operating Income (%)[1]
President and CEO	Construction Materials and Contracting	37.5	37.5	—	—	—	20.0	5.0
President and CEO	Construction Services	—	—	75.0[4]	—	—	20.0	5.0
President and CEO	Exploration and Production	—	—	—	56.25	18.75	20.0	5.0
President and CEO	Pipeline and Energy Services	37.5	37.5	—	—	—	20.0	5.0
President and CEO	Electric and Natural Gas Distribution	37.5	37.5	—	—	—	20.0	5.0

[1] Pretax operating income excludes (i) depreciation, depletion, and amortization, with non-cash ceiling test charges treated as depreciation and (ii) the accounting effects of the segment being moved from continuing operations to discontinued operations.

[2] Margin enhancement is defined as operations and maintenance expense cost below a target of $102 million, excluding accounting changes due to the segment being moved from continuing operations to discontinued operations.

[3] Earnings per share are diluted and adjusted and exclude (i) Fidelity and (ii) the effect on earnings at the MDU Resources Group, Inc. level of intersegment eliminations.

[4] Earnings are defined as GAAP earnings.

Our Named Executive Officers' Target Annual Incentive Compensation

The compensation committee established the named executive officers' 2015 target annual incentive as a percentage of each officer's base salary as follows:

- Mr. Goodin's 2015 target annual incentive was reduced from 150% to 100% of base salary, or $755,000, based on the competitive assessment, which showed median annual incentives of $955,000 for the salary survey companies and $659,000 for the performance graph peer group. The committee's rationale was, in conjunction with an increase in target long-term incentive compensation, to bring Mr. Goodin's total compensation in close alignment with the performance graph peer group, but below the survey data.

- Mr. Schwartz's 2015 target annual incentive was increased to 65% of base salary, which was the percent associated with his new salary grade J.

- Mr. Barney's 2015 target annual incentive was set at 80% of base salary, a decrease from 85% of base salary in 2014. The decrease was part of the committee's plan to reduce his annual target incentive to 65% of base salary, the target annual incentive associated with salary grade J, by 2017, while increasing his long-term incentive target to the guideline for his salary grade over the same time period.
- Mr. Thiede's 2015 target incentive was also decreased from 85% to 80% of base salary, continuing the transition of his incentive compensation from what it had been prior to his promotion in 2013 to having a target equal to those of other salary grade J participants by 2017.
- Mr. O'Bryan's 2015 target incentive was increased from 75% to 200% of base salary in order to compensate him for not receiving a long-term incentive award in 2015 and
- Mr. Bietz's 2015 target incentive was unchanged at 65% of base salary, which was consistent with the percent associated with his salary grade.

Company Goals Applicable to All Executives

As in prior years, the compensation committee established an MDU Resources Group, Inc. goal applicable to all executives that comprised 25% of the annual incentive award. However, for 2015, in light of the potential marketing of Fidelity, the compensation committee divided this goal into two components:

- MDU Resources Group, Inc. Component
  - comprised of all business segments except Fidelity
  - constituted 20% of the annual incentive, reduced from 25% in prior years
  - based on diluted adjusted earnings per share, excluding Fidelity
  - excludes the effect on earnings at the company level of intersegment eliminations, the effect on other business segments and on MDU Resources Group, Inc. of Fidelity becoming a discontinued operation for accounting purposes for 2015, and the income statement impact of a loss on a board-approved asset sale or disposition other than Fidelity
  - payout could range from no payment if results were below 85% level of $0.95 to a 200% payout if results were $1.29 or higher
  - target set at $1.12, as adjusted, below 2014 target of $1.48 and below adjusted 2014 results of $1.50 to reflect continued solid execution in all business segments, significant investments in our electric and natural gas distribution, and the exclusion of Fidelity.

Earnings per share for 2015 were, on a GAAP basis, $(3.20) and, on an adjusted basis excluding Fidelity and as described above, were $0.85, which was below the threshold amount for payment. The payment on this component was 0.0% of target.

- Fidelity Exploration & Production Company Component
  - comprised of Fidelity
  - constituted 5% of the annual incentive
  - based on pretax operating income excluding depreciation, depletion, and amortization
  - target set at $106 million for the year to reflect anticipated production, planned capital expenditures, and operations and maintenance expense
  - payout could range from no payment if results were below 80% of target or $84.8 million to a 200% payout if results were $127.2 million or higher for the year
  - a sale of Fidelity during 2015 would trigger a prorated payment on earned incentives measured in cumulative monthly results versus cumulative monthly goals.

Because over 75% of the assets of Fidelity were sold prior to December 31, 2015, the target of $106 million was adjusted, based on the cumulative monthly results, to $99.7 million. The 2015 results on the Fidelity goal were $96.5 million, equating to a 86.6% of target payment on this component.

Construction Materials and Contracting Segment Earnings Per Share and Return on Invested Capital Goals

For Mr. Barney, 75% of the 2015 award opportunity was based on allocated earnings per share and return on invested capital, equally weighted. The committee set the 2015 allocated earnings per share target at $0.94, which was higher than the 2014 target of $0.83 and actual results of $0.79, to reflect anticipated higher margins, partially offset by reduced backlog and flat material sales. The committee set the 2015 return on invested capital target at 7.2%, higher than the 2014 target of 6.3% and the 2014 actual results of 6.2%, due to higher anticipated earnings. Payout could range from no payment if the results were below the 70% of target or $0.66 earnings per share and 5.0% return on invested capital to a 200% payout if:

- 2015 allocated earnings per share for the segment were at or above the 115% of target or $1.08 and
- 2015 return on invested capital was at or above 115% of target or 8.3%.

The construction materials and contracting segment's 2015 earnings per share and return on invested capital were 150% and 144.4% of their respective 2015 targets, equating to 200% and 200%, respectively, of the target amount attributable to those components, which coupled with MDU Resources Group, Inc.'s component being 0.0% of target and the Fidelity component being 86.6% of target, resulted in a 2015 annual incentive payment for Mr. Barney of $487,588 or 154.3% of target.

Construction Services Segment Earnings Goal

For Mr. Thiede, the committee retained its approach from 2014, where 75% of his annual incentive award opportunity was based on the construction services segment's 2015 GAAP earnings. Target earnings levels were selected to balance the difficulty in forecasting, as well as earnings volatility for that segment. Specifically, target earnings of $26 million would be needed to meet the weighted average cost of capital, and earnings of $54.5 million, the result necessary to trigger payment of the maximum award, would be needed to drive a return on invested capital of approximately 15%. The committee felt these increased earnings levels from the 2014 target were appropriate given that they were above the business segment's 2015 projected weighted average cost of capital. Payout could range from no payment if the results were below the 85% of target earnings (increased from 70% in 2014 to be consistent with other business segment heads) or $22.1 million to 200% (reduced from 250% in 2014 to be consistent with other business segment heads) of the target amount if the results were at or above $54.5 million.

The construction services segment's 2015 earnings were $23.8 million, equating to a 57.7% payment on the segment's earnings component, which coupled with MDU Resources Group, Inc.'s earnings per share being 0.0% of target and the Fidelity component being 86.6% of target, resulted in a 2015 annual incentive payment for Mr. Thiede of $161,857 or 47.6% of target.

Exploration and Production Segment Pretax Operating Income and Margin Enhancement Goals

For 2015, the compensation committee changed the goal for the exploration and production segment from a single earnings as adjusted goal to two goals: pretax operating income and margin enhancement.

For Mr. O'Bryan, 56.25% of his 2015 award opportunity was based on the exploration and production segment's pretax operating income, excluding (i) depreciation, depletion, and amortization, with non-cash ceiling test charges treated as depreciation and (ii) accounting effects of the segment being moved from continuing operations to discontinued operations. The committee set the exploration and production segment's 2015 pretax operating income target at $106 million for the year reflecting anticipated production, operations and maintenance expense, and planned capital expenditures. Payout could range from no payment if 2015 pretax operating income was below the 80% level of target or $84.8 million to a 200% payout if the segment's 2015 pretax operating income was at or above the 120% level or $127.2 million for the year.

Because over 75% of the assets of Fidelity were sold prior to December 31, 2015, the target of $106 million was adjusted, based on the cumulative monthly results, to $99.7 million. The segment's 2015 pretax operating income was $96.5 million equating to a 86.6% payment on this component.

Margin enhancement was used for 18.75% of Mr. O'Bryan's award opportunity, with margin enhancement defined as operations and maintenance expense below a target of $102 million for the year. Payout could range from no payment if 2015 margin enhancement was higher than the 100% level of $102 million to a 200% payout if 2015 margin enhancement was equal to or less than the 92.5% level of target or $94.4 million for the year.

Because over 75% of the assets of Fidelity were sold prior to December 31, 2015, the target of $102 million was adjusted, based on the cumulative monthly results, to $95.4 million. The segment's 2015 operations and maintenance expense was $91.1 million equating to a 160.1% payment on this component.

Mr. O'Bryan was required to remain employed by Fidelity until the time of sale in order to receive payment. Since most of Fidelity was sold prior to December 31, 2015, and Mr. O'Bryan remained employed through that date, when coupled with MDU Resources Group, Inc.'s earnings per share being 0.0% of target and the Fidelity component being 86.6% of target, this resulted in a 2015 annual incentive payment for Mr. O'Bryan of $747,000 or 83.0% of target.

Pipeline and Energy Services Segment Earnings Per Share, Return on Invested Capital, and Safety Goals

For Mr. Bietz, 75% of his 2015 award opportunity was based on the pipeline and energy service segment's allocated earnings per share and target return on invested capital, equally weighted. For 2015, the committee set the pipeline and energy service segment's allocated earnings per share target at $1.64 and return on invested capital target at 5.6%. The 2015 earnings per share target was higher than the 2014 target of $0.98 and 2014 actual of $1.36, reflecting expected higher earnings due to the operation of the Dakota Prairie Refinery and the full impact of the 2014 rate case, partially offset by anticipated lower prices at the Pronghorn facility and higher operations and maintenance expense. For the same reasons, the 2015 return on invested capital target of 5.6% was set higher than the 2014 target of 3.9% and the 2014 actual results of 5.1%. Payout could range from no payment if the results were below the 85% of target or $1.39 earnings per share and 4.8% return on invested capital to a 200% payout if:

- the 2015 allocated earnings per share for the segment were at or above the 115% of target or $1.89 and
- the 2015 return on invested capital was at or above the 115% of target or 6.4%.

Mr. Bietz also had five individual goals relating to safety results with each goal that was not met reducing the annual incentive award by 1%. The five individual goals were:

- each established local safety committee will conduct eight meetings per year
- each established local safety committee must conduct four site assessments per year
- 90% (increased from 85%) or more of motor vehicle accidents and personal injuries must be reported by the end of the next business day
- achieve the targeted vehicle accident incident rate of 1.75 (decreased from 1.85) or less and
- achieve the targeted personal injury incident rate of 1.85 (decreased from 2.1) or less.

Results at the pipeline and energy services segment (before adjustment for the five safety goals) were negative on 2015 allocated earnings per share and return on invested capital, equating to 0.0% and 0.0%, respectively, of the target amount attributable to those components. These results, coupled with MDU Resources Group, Inc.'s earnings per share being 0.0% of target, the Fidelity component being 86.6% of target, and four of the five safety goals being met, resulted in 4.3% of the total annual incentive award target being met. Because of his retirement in July 2015, Mr. Bietz did not receive payment of his annual incentive.

Electric and Natural Gas Distribution Segments Earnings Per Share and Return on Invested Capital Goals

For the electric and natural gas distribution segments, 75% of the 2015 award opportunity was based on allocated earnings per share and target return on invested capital, equally weighted. The committee set the 2015 target for allocated earnings per share at $1.26, which was below the 2014 target of $1.30 but higher than the 2014 actual results of $1.16, to reflect expected higher earnings, partially offset by expected higher operations and maintenance expense and higher depreciation costs. The committee set the 2015 return on invested capital target at 5.3%, which was lower than the 2014 target level of 5.7% and equal to the 2014 actual results, to reflect higher invested capital in 2015 with incremental earnings associated with these investments not being fully realized until after 2015. The 2015 return on invested capital target was above the segment's projected 2015 weighted average cost of capital. Payout could range from no payment if the allocated earnings per share and return on invested capital results were below the 85% of target or $1.07 earnings per share and 4.5% return on invested capital, respectively, to a 200% payout if:

- the 2015 allocated earnings per share for the segment were at or above the 115% of target or $1.45 and
- the 2015 return on invested capital was at or above the 115% of target or 6.1%.

The electric and natural gas distribution segments' 2015 earnings per share and return on invested capital were less than 85% of their respective 2015 targets, equating to 0.0% and 0.0%, respectively, of the target amount attributable to those components. These results, coupled with MDU Resources Group, Inc.'s earnings per share being 0.0% of target and the Fidelity component being 86.6% of target, led to overall results for these segments of 4.3% of the 2015 target annual incentive award.

The following four tables show the 2014 and 2015 incentive plan performance targets and results by business segment:

2014 Incentive Plan Performance Targets

Name	EPS Business Segment ($)	ROIC Business Segment (%)	Earnings Business Segment (millions) ($)	EPS MDU Resources ($)
Construction Materials and Contracting	0.83	6.3	—	1.48
Construction Services	—	—	20.9	1.48
Exploration and Production	—	—	95.5	1.48
Pipeline and Energy Services	0.98	3.9	—	1.48
Electric and Natural Gas Distribution	1.30	5.7	—	1.48

2014 Incentive Plan Results

	EPS Business Segment		ROIC Business Segment		Earnings Business Segment		EPS MDU Resources	
Name	($)	(% of Target)	(%)	(% of Target)	(millions) ($)	(% of Target)	($)	(% of Target)
Construction Materials and Contracting	0.79	88.0	6.2	96.0	—	—	1.50	109
Construction Services	—	—	—	—	54.4	250.0	1.50	109
Exploration and Production	—	—	—	—	82.0	29.3	1.50	109
Pipeline and Energy Services	1.36	200.0	5.1	200.0	—	—	1.50	109
Electric and Natural Gas Distribution	1.16	46.2	5.3	64.9	—	—	1.50	109

2015 Incentive Plan Performance Targets

Name	EPS Business Segment ($)	ROIC Business Segment (%)	Earnings Business Segment (millions) ($)	Margin Enhancement Business Segment (millions) ($)	EPS MDU Resources ($)	Pretax Operating Income E&P Segment (millions) ($)
Construction Materials and Contracting	0.94	7.2	—	—	1.12	106
Construction Services	—	—	26.0	—	1.12	106
Exploration and Production	—	—	—	102.0	1.12	106
Pipeline and Energy Services	1.64	5.6	—	—	1.12	106
Electric and Natural Gas Distribution	1.26	5.3	—	—	1.12	106

2015 Incentive Plan Results

	EPS Business Segment		ROIC Business Segment		Earnings Business Segment		Margin Enhancement Business Segment[1]		EPS MDU Resources		Pretax Operating Income E&P Segment[2]	
Name	($)	(% of Target)	(%)	(% of Target)	(millions) ($)	(% of Target)	(millions) ($)	(% of Target)	($)	(% of Target)	(millions) ($)	(% of Target)
Construction Materials and Contracting	1.41	200.0	10.4	200.0	—	—	—	—	0.85	0	96.5	86.6
Construction Services	—	—	—	—	23.8	57.7	—	—	0.85	0	96.5	86.6
Exploration and Production	—	—	—	—	—	—	91.1	160.1	0.85	0	96.5	86.6
Pipeline and Energy Services	(0.50)	0	(0.3)	0	—	—	—	—	0.85	0	96.5	86.6
Electric and Natural Gas Distribution	0.97	0	4.4	0	—	—	—	—	0.85	0	96.5	86.6

[1] Because over 75% of the assets of Fidelity were sold prior to December 31, 2015, the target of $102 million was adjusted, based on the cumulative monthly results, to $95.4 million. The percent of target annual incentive compensation earned in the table reflects this adjustment.

[2] Because over 75% of the assets of Fidelity were sold prior to December 31, 2015, the target of $106 million was adjusted, based on the cumulative monthly results, to $99.7 million. The percent of target annual incentive compensation earned in the table reflects this adjustment.

Messrs. Goodin's and Schwartz's 2015 annual incentives were earned at 49.9% of target based on the following:

	Column A Percentage of Annual Incentive Target Achieved	Column B Percentage of Average Invested Capital	Column A x Column B
Construction Materials and Contracting	154.3%	19.6%	30.2%
Construction Services	47.6%	6.9%	3.3%
Exploration and Production	83.0%	16.8%	13.9%
Pipeline and Energy Services	4.3%	13.1%	0.6%
Electric and Natural Gas Distribution	4.3%	43.6%	1.9%
Total (Payout Percentage)			49.9%

Additional Annual Incentives

Mr. Barney received an additional annual incentive opportunity of $150,000 tied to the construction materials and contracting segment's operating cash flow. The committee granted this award to provide an extra focus on cash flow management, where Mr. Barney's success would help fund growth opportunities at other business segments. Payment would be made only if the goal was met or exceeded, without any scaling of payment for results above or below the target. The committee set operating cash flow of $109.2 million as the goal, excluding the effect of acquisitions or dispositions approved by the board of directors. The 2015 results were $154.1 million resulting in a payment of $150,000 to Mr. Barney.

Mr. O'Bryan had two additional annual incentive opportunities. He received a cash retention award opportunity in November 2014 before his promotion, where he would receive $150,000 if he remained an active full-time employee of Fidelity through December 31, 2015 and maintained a performance rating of "meets expectations" or higher during 2015. He also was granted in May 2015 a sales bonus incentive of 0.075% of the sale price of Fidelity, plus an award equal to six months' salary of $225,000. The committee believed that Mr. O'Bryan's involvement in the Fidelity sales process would likely bring significant incremental value and recognized the importance of keeping Mr. O'Bryan incentivized to remain with the company and lead a successful sales effort. Mr. O'Bryan received the cash retention award of $150,000 and the sales bonus incentive of $237,425, plus the six months' salary.

The table below lists each named executive officer's 2015 base salary, target annual incentive percentage, and the annual (regular and additional) incentives earned.

Name	2015 Base Salary (000s) ($)	2015 Target Annual Incentive (%)	2015 Annual Incentive Earned (% of Target)	2015 Annual Incentive Earned (000s) ($)	2015 Additional Annual Incentives Earned (000s) ($)
David L. Goodin	755.0	100.0	49.9	376.7	
Doran N. Schwartz	380.0	65.0	49.9	123.3	
David C. Barney	395.0	80.0	154.3	487.6	150.0
Jeffrey S. Thiede	425.0	80.0	47.6	161.9	
Patrick L. O'Bryan	450.0	200.0	83.0	747.0	612.4 [1]
Steven L. Bietz[2]	395.0	65.0			

[1] Consists of $150,000 cash retention award, $237,425 sales bonus, and $225,000 salary.

[2] Because of his retirement in July 2015, Mr. Bietz did not receive payment of his annual incentive.

Deferral of Annual Incentive Compensation

We provide executives the opportunity to defer receipt of earned annual incentives. If an executive chooses to defer his or her annual incentive, we will credit the deferral with interest at a rate determined by the compensation committee. For 2015, the committee chose to use the average of (i) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "A" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12, and (ii) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "Baa" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12. This resulted in an interest rate of 4.66%. The compensation committee's reasons for using this approach recognized:

- incentive deferrals are a low-cost source of capital for the company and
- incentive deferrals are unsecured obligations and, therefore, carry a higher risk to the executives.

2015 Long-Term Incentives

Performance Share Awards

We use the Long-Term Performance-Based Incentive Plan, which has been approved by our stockholders, for long-term incentive compensation, with performance shares as the primary form of long-term incentive compensation. We have not granted stock options since 2001, and in 2011 we amended the plan to no longer permit the grant of stock options or stock appreciation rights; no stock options, stock appreciation rights, or restricted shares are outstanding.

The compensation committee has used relative stockholder return in comparison to the performance graph peer group as the performance measure for long-term incentive compensation for a number of years, including the 2015 performance share awards. Before it made the 2015 performance share awards, the committee revised the peer group as set forth below. The new peer group excluded some of the exploration and production companies and added other companies in the utility and pipeline business segments, as well as companies in the construction services and construction materials business segments to better reflect the company's mix of business segments and reduction of capital committed to Fidelity. The committee also added provisions to the award agreement for removing the two remaining exploration and production companies from the peer group if Fidelity was sold during the performance period, with the company's performance measured against the two peers groups on a prorated basis.

The revised performance graph peer group consisted of the following companies when the committee granted performance shares in February 2015.

- ALLETE, Inc.
- Alliant Energy Corporation
- Atmos Energy Corporation
- Avista Corporation
- Bill Barrett Corporation
- Black Hills Corporation
- EMCOR Group, Inc.
- Granite Construction Incorporated
- IDACORP, Inc.
- Integrated Electrical Services, Inc.
- Markwest Energy Partners, L.P.
- Martin Marietta Materials, Inc.
- MYR Group Inc.
- National Fuel Gas Company
- Northwest Natural Gas Company
- NorthWestern Corporation
- Quanta Services, Inc.
- Questar Corporation
- SM Energy Company
- Sterling Construction Company, Inc.
- U.S. Concrete, Inc.
- Vectren Corporation
- Vulcan Materials Company

The performance measure is our total stockholder return over a three-year measurement period as compared to the total stockholder returns of the companies in our performance graph peer group over the same three-year period. The compensation committee selected the relative stockholder return performance measure because it believes executive pay under a long-term, capital accumulation incentive program such as this should align with our long-term performance in stockholder return as compared to other public companies in our industries. Payments are made in company stock; dividend equivalents are paid in cash. No dividend equivalents are paid on unvested performance shares.

Total stockholder return is the percentage change in the value of an investment in the common stock of a company, from the closing price on the last trading day in the calendar year preceding the beginning of the performance period, through the last trading day in the final year of the performance period. It is assumed that dividends are reinvested in additional shares of common stock at the frequency paid.

As with the target annual incentive, we determined the target long-term incentive for a given position in part from the competitive assessment and in part by the compensation committee's judgment on the impact each position has on our total stockholder return. At the February 2015 meeting, the committee reviewed the target levels of annual and long-term incentive compensation for the chief executive officer included in a special report prepared by the vice president-human resources. Based on the competitive data, the committee increased the chief executive officer's target long-term incentive for 2015 from 150% to 225% of base salary.

Mr. Schwartz's target long-term incentive was increased from 75% to 90% of base salary, consistent with his move to salary grade J.

Messrs. Barney's and Thiede's target long-term incentive compensation increased from 60% to 70% of base salary for 2015, which was part of the committee's plan to increase their long-term incentive target to 90% of base salary by 2017, while at the same time decreasing their annual incentive target to the guideline associated with salary grade J.

Mr. O'Bryan did not receive a long-term incentive for 2015 because of the potential marketing of Fidelity, with any sale likely to occur before the conclusion of the three-year performance period.

Mr. Bietz's 2015 target long-term incentive was 90% of base salary and was unchanged from 2014, consistent with his salary grade.

On February 12, 2015, the board of directors, upon recommendation of the compensation committee, made performance share grants to the named executive officers, except for Mr. O'Bryan. The compensation committee determined the target number of performance shares granted to each named executive officer by multiplying the named executive officer's 2015 base salary by his target long-term incentive and then dividing this product by the average of the closing prices of our stock from January 1, 2015 through January 22, 2015, as shown in the following table:

Name	2015 Base Salary to Determine Target ($)	2015 Target Long-Term Incentive at Time of Grant (%)	2015 Target Long-Term Incentive at Time of Grant ($)	Average Closing Price of Our Stock From January 1 Through January 22 ($)	Resulting Number of Performance Shares Granted on February 12 (#)
David L. Goodin	755,000	225	1,698,750	23.54	72,164
Doran N. Schwartz	380,000	90	342,000	23.54	14,528
David C. Barney	395,000	70	276,500	23.54	11,745
Jeffrey S. Thiede	425,000	70	297,500	23.54	12,638
Patrick L. O'Bryan	—	—	—	—	—
Steven L. Bietz	395,000	90	355,500	23.54	15,101

Assuming our three-year (2015 through 2017) total stockholder return is positive, from 0% to 200% of the target grant will be paid out in February 2018 depending on our total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage will be a function of our rank against our performance graph peer group as delineated in the following table:

Long-Term Incentive Payout Percentages

The Company's Percentile Rank	Payout Percentage of February 12, 2015 Grant
75th or higher	200%
50th	100%
25th	20%
Less than 25th	0%

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2018 at the same time as the performance share awards are paid.

As had been established for awards granted beginning in 2011, if our total stockholder return is negative, the shares and dividend equivalents otherwise earned, if any, will be reduced in accordance with the following table:

Total Stockholder Return	Reduction in Award
0% through -5%	50%
-5.01% through -10%	60%
-10.01% through -15%	70%
-15.01% through -20%	80%
-20.01% through -25%	90%
-25.01% or below	100%

The named executive officers must retain 50% of the net after-tax shares that are earned pursuant to this long-term incentive award until the earlier of (i) the end of the two-year period commencing on the date any shares earned under the award are issued and (ii) the executive's termination of employment.

No Payment in February 2015 for 2012 Grants under the Long-Term Performance-Based Incentive Plan

We granted performance shares to our named executive officers under the Long-Term Performance-Based Incentive Plan on February 16, 2012, for the 2012 through 2014 performance period. Our total stockholder return for the 2012 through 2014 performance period was 18.7%, which resulted in no shares or dividend equivalents being paid to the named executive officers. Messrs. Barney, Thiede, and O'Bryan did not participate in the program in 2012.

Mr. Bietz Retirement Payment

In connection with Mr. Bietz's retirement effective at the close of business on July 17, 2015, the committee and the board approved the entry into a waiver and voluntary release agreement. The agreement provided for a lump-sum payment of $750,000, less applicable tax withholding amounts, for the release and in recognition of his 34 years of service and in transforming WBI Holdings, Inc. from a dry gas storage and transmission company to a multi-faceted energy services business, including crude refining.

Clawback

In November 2005, we implemented a guideline for repayment of incentives due to accounting restatements, commonly referred to as a clawback policy, whereby the compensation committee may seek repayment of annual and long-term incentives paid to executives if accounting restatements occur within three years after the payment of incentives under the annual and long-term plans. Under our clawback policy, the compensation committee may require executives to forfeit awards and may rescind vesting, or the acceleration of vesting, of an award.

Post-Termination Compensation and Benefits

Pension Plans

Effective in 2006, we no longer offer defined benefit pension plans to new non-bargaining unit employees. The defined benefit plans available to employees hired before 2006 were amended to cease benefit accruals as of December 31, 2009. The frozen benefit provided through our qualified defined benefit pension plans is determined by years of service and base salary. Effective 2010, for those employees who were participants in defined benefit pension plans and for executives and other non-bargaining unit employees hired after 2006, the company offers increased company contributions to our 401(k) plan. For non-bargaining unit employees hired after 2006, the retirement contribution is 5% of plan eligible compensation. For participants hired prior to 2006, retirement contributions are based on the participant's age as of December 31, 2009. The retirement contribution is 11.5% for Messrs. Goodin and Bietz, 10.5% for Mr. Schwartz, and 5% for Messrs. Barney, Thiede, and O'Bryan, which amounts may be reduced in accordance with the provisions of the 401(k) plan.

Supplemental Income Security Plan

Benefits Offered

We offer certain key managers and executives, including all of our named executive officers, except Mr. Thiede and Mr. O'Bryan, benefits under our nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. The SISP has a ten-year vesting schedule and was amended to add an additional vesting requirement for benefit level increases occurring on or after January 1, 2010. Effective February 11, 2016, the SISP was amended to freeze the plan to new participants and to current participants at their current benefit levels. The SISP provides participants with additional retirement income and death benefits.

We believe the SISP is effective in retaining the talent necessary to drive long-term stockholder value. In addition, we believe the ten-year vesting provision of the SISP, augmented by an additional three years of vesting for benefit level increases occurring on or after January 1, 2010, helps promote retention of key executive officers.

Benefit Levels

The chief executive officer recommends benefit level increases to the compensation committee for participants except himself. The chief executive officer considers, among other things, the participant's salary in relation to the salary ranges that correspond with the SISP benefit levels, the participant's performance, the performance of the applicable business segment or the company, and the cost associated with the benefit level increase.

The named executive officers did not receive any SISP benefit level increases in 2015. The following table reflects our named executive officers' SISP levels as of December 31, 2015:

Name	December 31, 2015 Annual SISP Benefits Survivor ($)	Retirement ($)
David L. Goodin	552,960	276,480
Doran N. Schwartz	262,464	131,232
David C. Barney	262,464	131,232
Jeffrey S. Thiede	N/A	N/A
Patrick L. O'Bryan	N/A	N/A
Steven L. Bietz	386,640	193,320

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, or NQDCP, effective January 1, 2012, to provide deferred compensation for a select group of management or highly compensated employees who do not participate in the SISP. The compensation committee, upon recommendation from the chief executive officer, determines which employees will participate in the NQDCP for any year. The compensation committee determines the amount of employer contributions under the plan, which are credited to plan accounts and not funded. After satisfying a four-year vesting requirement for each contribution, the contributions and investment earnings will be distributed to the executive in a lump sum upon separation from service with the company or in annual installments commencing upon the later of (i) separation from service and (ii) age 65. The four-year vesting requirement is waived if the participant dies while employed by the company.

The committee, upon recommendation of the chief executive officer, selected Mr. Thiede as a participant for 2015 with an employer contribution of $150,000 or 35.29% of his base salary as of January 1, 2015. The contribution was awarded to recognize his strong leadership at the construction services segment, which delivered a twelve-month return on invested capital, measured at June 30, 2014, of 19.2% as compared to a median return on invested capital of 9.5% at the relevant companies in our performance graph peer group. We believe that Mr. Thiede's participation in this plan and the four-year vesting requirement enhance retention since he cannot participate in any of our defined benefit retirement plans.

Impact of Tax and Accounting Treatment

The compensation committee may consider the impact of tax and/or accounting treatment in determining compensation. Section 162(m) of the Internal Revenue Code places a limit of $1 million on the amount of compensation paid to certain officers that we may deduct as a business expense in any tax year unless, among other things, the compensation qualifies as performance-based compensation, as that term is used in Section 162(m). Generally, long-term incentive compensation and annual incentive awards for our chief executive officer and those executive officers whose overall compensation is likely to exceed $1 million are structured to be deductible for purposes of Section 162(m) of the Internal Revenue Code, but we may pay compensation to an executive officer that is not deductible. All incentive compensation paid to our named executive officers in 2015 satisfied the requirements for deductibility.

Section 409A of the Internal Revenue Code imposes additional income taxes on executive officers for certain types of deferred compensation if the deferral does not comply with Section 409A. We have amended our compensation plans and arrangements affected by Section 409A with the objective of not triggering any additional income taxes under Section 409A.

Section 4999 of the Internal Revenue Code imposes an excise tax on payments to executives and others of amounts that are considered to be related to a change of control if they exceed levels specified in Section 280G of the Internal Revenue Code. To the extent a change of control triggers liability for an excise tax, payment of the excise tax will be made by the individual. The company will not pay the excise tax. We do not consider the potential impact of Section 4999 or 280G when designing our compensation programs.

The compensation committee also considers the accounting and cash flow implications of various forms of executive compensation. In our financial statements, we record salaries and annual incentive compensation as expenses in the amount paid, or to be paid, to the named executive officers. For our equity awards, accounting rules also require that we record an expense in our financial statements. We calculate the accounting expense of equity awards to employees in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock-based compensation.

Stock Ownership Requirements

We instituted stock ownership guidelines on May 5, 1993, which we revised in November 2010 to provide that executives who participate in our Long-Term Performance-Based Incentive Plan are required within five years to own our common stock equal to a multiple of their base salaries. Stock owned through our 401(k) plan or by a spouse is considered in ownership calculations. Unvested performance shares and other unvested equity awards are not considered in ownership calculations. The level of stock ownership compared to the requirements is determined based on the closing sale price of the stock on the last trading day of the year and base salary at December 31 of each year. Each February the compensation committee receives a report on the status of stockholdings by executives. The committee may, in its sole discretion, grant an extension of time to meet the ownership requirements or take such other action as it deems appropriate to enable the executive to achieve compliance with the policy. The table shows the named executive officers' holdings as of December 31, 2015:

Name	Assigned Guideline Multiple of Base Salary	Actual Holdings as a Multiple of Base Salary	Number of Years at Guideline Multiple (#)
David L. Goodin	4X	1.78	3.00 [1]
Doran N. Schwartz	3X	2.24	5.87 [2]
David C. Barney	3X	0.39	2.00 [3]
Jeffrey S. Thiede	3X	0.11	2.00 [3]
Patrick L. O'Bryan[4]	N/A	N/A	N/A
Steven L. Bietz[5]	—	—	—

[1] Participant must meet ownership requirement by January 1, 2018.

[2] Participant should have met ownership requirement by February 17, 2015.

[3] Participant must meet ownership requirement by January 1, 2019.

[4] Participant is not subject to ownership requirement because he did not receive a long-term incentive award.

[5] Mr. Bietz retired effective July 17, 2015.

The compensation committee may consider the policy and the executive's stock ownership in determining compensation. The committee, however, did not do so with respect to 2015 compensation.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits Section 16 officers from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership. See the Security Ownership section of the proxy statement for our policy on margin accounts and pledging of our stock.

Compensation Committee Report

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Regulation S-K, Item 402(b), with management. Based on the review and discussions referred to in the preceding sentence, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our proxy statement on Schedule 14A.

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

Summary Compensation Table for 2015

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)[1]	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)[2]	All Other Compensation ($) (i)	Total ($) (j)
David L. Goodin	2015	755,000	—	1,386,992	—	376,745	—	39,411 [3]	2,558,148
President and CEO	2014	685,000	—	1,385,135	—	830,915	631,901	38,686	3,571,637
	2013	625,000	—	1,241,280	—	1,610,625	532,991	37,517	4,047,413
Doran N. Schwartz	2015	380,000	—	279,228	—	123,253	—	35,571 [3]	818,052
Vice President	2014	360,000	—	363,959	—	163,080	273,974	34,956	1,195,969
and CFO	2013	345,000	—	342,579	—	296,355	28,459	34,881	1,047,274
David C. Barney	2015	395,000	—	225,739	—	637,588	9,530	22,556 [3]	1,290,413
President and CEO of	2014	—	—	—	—	—	—	—	—
Knife River Corporation	2013	—	—	—	—	—	—	—	—
Jeffrey S. Thiede	2015	425,000	—	242,902	—	161,857	—	172,506 [3]	1,002,265
President and CEO of	2014	400,000	—	323,529	—	730,150	—	96,481	1,550,160
MDU Construction Services Group, Inc.	2013	367,068	—	—	—	825,000	—	66,282	1,258,350
Patrick L. O'Bryan	2015	441,918	—	—	—	1,359,425	—	21,356 [3]	1,822,699
President and CEO of	2014	—	—	—	—	—	—	—	—
Fidelity Exploration & Production Company	2013	—	—	—	—	—	—	—	—
Steven L. Bietz	2015	214,274	—	290,241	—	—	15,254	787,351 [3]	1,307,120
President and CEO of	2014	380,000	—	461,026	—	333,552	550,417	39,771	1,764,766
WBI Energy, Inc.	2013	367,700	—	438,167	—	119,503	—	38,591	963,961

[1] Amounts in this column represent the aggregate grant date fair value of performance share awards calculated in accordance with Financial Accounting Standards Board (FASB) generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards were or will be forfeited. The amounts for 2015 were calculated using a Monte Carlo simulation, as described in footnote 2 to the Grants of Plan-Based Awards table.

[2] Amounts shown represent the change in the actuarial present value for years ended December 31, 2013, 2014, and 2015 for the named executive officers' accumulated benefits under the pension plan, excess SISP, and SISP, collectively referred to as the "accumulated pension change," plus above-market earnings on deferred annual incentives, if any. The amounts shown are based on accumulated pension change and above-market earnings as of December 31, 2013, 2014, and 2015, as follows:

	Accumulated Pension Change			Above-Market Earnings		
Name	12/31/2013 ($)	12/31/2014 ($)	12/31/2015 ($)	12/31/2013 ($)	12/31/2014 ($)	12/31/2015 ($)
David L. Goodin	532,986	631,901	(64,074)	5	—	—
Doran N. Schwartz	28,459	273,974	(31,393)	—	—	—
David C. Barney	—	—	9,530	—	—	—
Jeffrey S. Thiede	—	—	—	—	—	—
Patrick L. O'Bryan	—	—	—	—	—	—
Steven L. Bietz	(261,546)	550,417	15,254	—	—	—

[3] All Other Compensation is comprised of:

	401(k) ($)[a]	Life Insurance Premium ($)	Matching Charitable Contribution ($)	Nonqualified Defined Contribution Plan ($)	Severance Payments ($)	Total ($)
David L. Goodin	38,425	156	830	—	—	39,411
Doran N. Schwartz	35,000	156	415	—	—	35,571
David C. Barney	21,200	156	1,200	—	—	22,556
Jeffrey S. Thiede	21,200	156	1,150	150,000	—	172,506
Patrick L. O'Bryan	21,200	156	—	—	—	21,356
Steven L. Bietz	35,000	91	2,260	—	750,000	787,351

[a] Represents company contributions to 401(k) plan, which include matching contributions and contributions made in lieu of pension plan accruals after pension plans were frozen at December 31, 2009.

Grants of Plan-Based Awards in 2015

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($) (l)
David L. Goodin	2/12/2015 [1]	188,750	755,000	1,510,000	—	—	—	—	—	—	—
	2/12/2015 [2]	—	—	—	14,433	72,164	144,328	—	—	—	1,386,992
Doran N. Schwartz	2/12/2015 [3]	61,750	247,000	494,000	—	—	—	—	—	—	—
	2/12/2015 [2]	—	—	—	2,906	14,528	29,056	—	—	—	279,228
David C. Barney	2/12/2015 [1]	—	150,000	—	—	—	—	—	—	—	—
	2/12/2015 [3]	79,000	316,000	632,000	—	—	—	—	—	—	—
	2/12/2015 [2]	—	—	—	2,349	11,745	23,490	—	—	—	225,739
Jeffrey S. Thiede	2/12/2015 [1]	85,000	340,000	680,000	—	—	—	—	—	—	—
	2/12/2015 [2]	—	—	—	2,528	12,638	25,276	—	—	—	242,902
Patrick L. O'Bryan	2/12/2015 [1]	225,000	900,000	1,800,000	—	—	—	—	—	—	—
	5/14/2015 [4]	—	462,425	—	—	—	—	—	—	—	—
Steven L. Bietz	2/12/2015 [3]	64,188	256,750	513,500	—	—	—	—	—	—	—
	2/12/2015 [2]	—	—	—	3,020	15,101	30,202	—	—	—	290,241

[1] Annual incentive for 2015 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

[2] Performance shares for the 2015-2017 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan. The aggregate grant date fair value of the performance share awards as shown in column (l) was calculated in accordance with Financial Accounting Standards Board (FASB) generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards were or will be forfeited. The amounts were calculated using a Monte Carlo simulation using blended volatility term structure ranges 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. The assumptions used for the performance shares awards in 2015 were:

	2015
Grant date fair value	$19.22
Blended volatility range	22.87% - 24.58%
Risk-free interest range	0.05% - 1.07%
Discounted dividends per share	$1.60

[3] Annual incentive for 2015 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

[4] Sales bonus incentive award granted in May 2015, with no threshold, target or maximum levels, plus an amount equal to six months salary of $225,000. The amount shown in the table is the actual amount earned for 2015 plus the $225,000.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Incentive Awards

Annual Incentive

On February 11, 2015, the compensation committee recommended the 2015 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 12, 2015. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on February 12, 2015, in columns (c), (d), and (e) and in the Summary Compensation Table as earned with respect to 2015 in column (g).

Executive officers may receive a payment of annual cash incentive awards based upon achievement of annual performance measures with a threshold, target, and maximum level. A target incentive award is established based on a percent of the executive's base salary. Based upon achievement of goals, actual payment may range from 0% to 200% of the target.

In order to be eligible to receive a payment of an annual incentive award under the Long-Term Performance-Based Incentive Plan, the executive officer must have remained employed by the company through December 31, 2015, unless the compensation committee determines otherwise. The committee has full discretion to determine the extent to which goals have been achieved, the payment level, whether any final payment will be made, and whether to adjust awards downward based upon individual performance. Unless otherwise determined and established in writing by the compensation committee within 90 days of the beginning of the performance period, the performance goals may not be adjusted if the adjustment would increase the annual incentive award payment. The compensation committee may use negative discretion and adjust any annual incentive award payment downward, using any subjective or objective measures as it shall determine. The application of any reduction, and the methodology used in determining any such reduction, is in the sole discretion of the compensation committee.

With respect to annual incentive awards granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan, executives who retire during the year at age 65 pursuant to their employer's bylaws remain eligible to receive an award. Subject to the compensation committee's discretion, executives who terminate employment for other reasons are not eligible for an award. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether any final payment will be made. Once performance goals are approved by the committee for executive incentive compensation plan awards, the committee generally does not modify the goals. However, if major unforeseen changes in economic and environmental conditions or other significant factors beyond the control of management substantially affected management's ability to achieve the specified performance goals, the committee, in consultation with the chief executive officer, may modify the performance goals. Such goal modifications will only be considered in years of unusually adverse or favorable external conditions.

Annual incentive awards earned for Messrs. Goodin and Schwartz were determined based on achievement of performance goals at the following business segments - (i) construction materials and contracting, (ii) construction services, (iii) exploration and production, (iv) pipeline and energy services, and (v) electric and natural gas distribution - and were calculated as follows:

	Column A Percentage of Annual Incentive Target Achieved	Column B Percentage of Average Invested Capital	Column A x Column B
Construction Materials and Contracting	154.3%	19.6%	30.2%
Construction Services	47.6%	6.9%	3.3%
Exploration and Production	83.0%	16.8%	13.9%
Pipeline and Energy Services	4.3%	13.1%	0.6%
Electric and Natural Gas Distribution	4.3%	43.6%	1.9%
Total (Payout Percentage)			49.9%

Messrs. Barney, Thiede, O'Bryan, and Bietz had 2015 award opportunities based 75% on performance goals at their respective segments, 20% on MDU Resources Group, Inc.'s diluted earnings per share attributable to all business segments except the exploration and production segment, as adjusted, and 5% on the exploration and production segment pretax operating income, as adjusted.

The 2015 target for the MDU Resources Group, Inc. 20% award opportunity was established based on MDU Resources Group, Inc.'s diluted earnings per share attributable to all business segments except the exploration and production segment, adjusted to exclude the effect on earnings at the company level of intersegment eliminations, the accounting effects on other business segments and on MDU Resources Group, Inc. of the exploration and production segment being moved from continuing operations to discontinued operations and the income statement impact of a loss on board approved asset sales or dispositions, other than the sale of the exploration and production segment.

The MDU Resources Group 20% award opportunity was:

MDU Resources Group, Inc.'s diluted adjusted 2015 earnings per share as a % of target	Corresponding payment of annual incentive target
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

The 2015 target for the exploration and production segment 5% award opportunity was established based on the segment's pretax operating income, adjusted to exclude depreciation, depletion, and amortization and the accounting effects of the segment being moved from continuing operations to discontinued operations.

The exploration and production segment 5% award opportunity was:

Exploration and Production's 2015 pretax operating income excluding DD&A as a % of target	Corresponding payment of annual incentive target
Less than 80%	0%
80%	25%
87%	50%
94%	75%
100%	100%
104%	120%
108%	140%
112%	160%
116%	180%
120%	200%

The 75% award opportunity available for Mr. Barney was:

Construction Materials & Contracting's 2015 earnings per share as a % of target (weighted 37.5%)	Corresponding payment of annual incentive target	Construction Materials & Contracting's 2015 return on invested capital as a % of target (weighted 37.5%)	Corresponding payment of annual incentive target
Less than 70%	0%	Less than 70%	0%
70%	25%	70%	25%
75%	37.5%	75%	37.5%
80%	50%	80%	50%
85%	62.5%	85%	62.5%
90%	75%	90%	75%
95%	87.5%	95%	87.5%
100%	100%	100%	100%
103%	120%	103%	120%
106%	140%	106%	140%
109%	160%	109%	160%
112%	180%	112%	180%
115%	200%	115%	200%

The 75% award opportunity available for Mr. Thiede was:

Construction Services' 2015 earnings* as a % of target	Corresponding payment of annual incentive target
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
122%	120%
144%	140%
166%	160%
188%	180%
209.5%	200%

*Earnings is defined as GAAP earnings reported for the construction services segment.

The 75% award opportunity available for Mr. O'Bryan was:

Exploration and Production's 2015 pretax operating income excluding DD&A as a % of target (weighted 56.25%)	Corresponding payment of annual incentive target	Exploration and Production's 2015 operations and maintenance expense as a % of target (weighted 18.75%)	Corresponding payment of annual incentive target
Less than 80%	0%	Greater than 100%	0%
80%	25%	100%	100%
87%	50%	98.5%	120%
94%	75%	97%	140%
100%	100%	95.5%	160%
104%	120%	94%	180%
108%	140%	92.5%	200%
112%	160%	—	—
116%	180%	—	—
120%	200%	—	—

The 75% award opportunity available for Mr. Bietz was:

Pipeline and Energy Services' 2015 earnings per share as a % of target (weighted 37.5%)	Corresponding payment of annual incentive target	Pipeline and Energy Services' 2015 return on invested capital as a % of target (weighted 37.5%)	Corresponding payment of annual incentive target
Less than 85%	0%	Less than 85%	0%
85%	25%	85%	25%
90%	50%	90%	50%
95%	75%	95%	75%
100%	100%	100%	100%
103%	120%	103%	120%
106%	140%	106%	140%
109%	160%	109%	160%
112%	180%	112%	180%
115%	200%	115%	200%

The pipeline and energy services segment also had five goals relating to the pipeline and energy services segment's safety results, and each goal that was not met would reduce Mr. Bietz's annual incentive award payment by 1%.

Additional Annual Incentives

On February 11, 2015, the compensation committee recommended an additional annual incentive award opportunity for Mr. Barney under the Long-Term Performance-Based Incentive Plan tied to the construction materials and contracting segment's operating cash flow, which would be measured without regard to acquisitions or dispositions approved by the company's board of directors. The board approved this opportunity at its meeting on February 12, 2015. This award opportunity is reflected in the Grants of Plan-Based Awards table at grant on February 12, 2015 in column (d) and in the Summary Compensation Table as earned with respect to 2015 in column (g).

The $150,000 award opportunity available for Mr. Barney was:

Construction Materials & Contracting's 2015 operating cash flow as a % of target	Corresponding payment of incentive target
Less than 100%	0%
100% or Greater	100%

On May 13, 2015, the compensation committee recommended an additional annual incentive award opportunity for Mr. O'Bryan tied to the sale of Fidelity Exploration & Production Company. The board approved this opportunity at its meeting on May 14, 2015. Mr. O'Bryan would receive a sales bonus incentive of 0.075% of the sale price of Fidelity, plus an amount equal to six months' salary of $225,000, if he remained employed by Fidelity through its sale. This award opportunity is reflected in the Grants of Plan-Based Awards table at grant on May 14, 2015 in column (d) and in the Summary Compensation Table as earned with respect to 2015 in column (g). Because there were no threshold, target, or maximum levels, the amount shown in the tables is the actual amount earned. Mr. O'Bryan received a cash retention award opportunity in November 2014 before his promotion, where he would receive $150,000 if he remained a full-time active employee of Fidelity through December 31, 2015, and maintained a performance rating of "meets expectations" or higher during 2015. The award opportunity is reflected in the Summary Compensation Table as earned with respect to 2015 in column (g).

For discussion of the specific incentive plan performance targets and results, please see the Compensation Discussion and Analysis.

Long-Term Incentive

On February 11, 2015, the compensation committee recommended long-term incentive grants for the named executive officers in the form of performance shares, and the board approved these grants at its meeting on February 12, 2015. These grants are reflected in columns (f), (g), (h), and (l) of the Grants of Plan-Based Awards table and in column (e) of the Summary Compensation Table.

If the company's 2015-2017 total stockholder return is positive, from 0% to 200% of the target grant will be paid out in February 2018, depending on our 2015-2017 total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage is determined as follows:

The Company's Percentile Rank	Payout Percentage of February 12, 2015 Grant
75th or higher	200%
50th	100%
25th	20%
Less than 25th	0%

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2018 at the same time as the performance share awards are paid.

If the common stock of a company in the peer group ceases to be traded at any time during the 2015-2017 performance period, the company will be deleted from the peer group. Percentile rank will be calculated without regard to the return of the deleted company. If MDU Resources Group, Inc. or a company in the peer group spins off a segment of its business, the shares of the spun-off entity will be treated as a cash dividend that is reinvested in MDU Resources Group, Inc. or the company in the peer group.

If the company's 2015-2017 total stockholder return is negative, the number of shares otherwise earned, if any, for the performance period will be reduced in accordance with the following table:

Total Stockholder Return	Reduction in Award
0% through -5%	50%
-5.01% through -10%	60%
-10.01% through -15%	70%
-15.01% through -20%	80%
-20.01% through -25%	90%
-25.01% or below	100%

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary and bonus to total compensation:

Name	Salary ($)	Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
David L. Goodin	755,000	—	2,558,148	29.5%
Doran N. Schwartz	380,000	—	818,052	46.5%
David C. Barney	395,000	—	1,290,413	30.6%
Jeffrey S. Thiede	425,000	—	1,002,265	42.4%
Patrick L. O'Bryan	441,918	—	1,822,699	24.2%
Steven L. Bietz	214,274	—	1,307,120	16.4%

Outstanding Equity Awards at Fiscal Year-End 2015

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[1]
David L. Goodin	—	—	—	—	—	—	—	63,956 [2]	1,171,674
Doran N. Schwartz	—	—	—	—	—	—	—	16,485 [2]	302,005
David C. Barney	—	—	—	—	—	—	—	3,843 [2]	70,404
Jeffrey S. Thiede	—	—	—	—	—	—	—	4,101 [2]	75,130
Patrick L. O'Bryan	—	—	—	—	—	—	—	—	—
Steven L. Bietz	—	—	—	—	—	—	—	16,287 [2]	298,378

[1] Value based on the number of performance shares reflected in column (i) multiplied by $18.32, the year-end closing price for 2015.

[2] Below is a breakdown by year of the plan awards:

Named Executive Officer	Award	Shares	End of Performance Period
David L. Goodin	2013	42,788	12/31/15
	2014	6,735	12/31/16
	2015	14,433	12/31/17
Doran N. Schwartz	2013	11,809	12/31/15
	2014	1,770	12/31/16
	2015	2,906	12/31/17
David C. Barney	2013	—	—
	2014	1,494	12/31/16
	2015	2,349	12/31/17
Jeffery S. Thiede	2013	—	—
	2014	1,573	12/31/16
	2015	2,528	12/31/17
Patrick L. O'Bryan	2013	—	—
	2014	—	—
	2015	—	—
Steven L. Bietz	2013	15,104	12/31/15
	2014	1,183	12/31/16
	2015	—	—

Shares for the 2013 award are shown at the target level (100%) based on results for the 2013-2015 performance cycle between threshold and target.

Shares for the 2014 award are shown at the threshold level (20%) based on results for the first two years of the 2014-2016 performance cycle below threshold. Mr. Bietz's shares are prorated to reflect his retirement effective July 17, 2015.

Shares for the 2015 award are shown at the threshold level (20%) based on results for the 2015-2017 performance cycle below threshold. Mr. Bietz's shares were forfeited because of his retirement effective July 17, 2015.

Pension Benefits for 2015

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
David L. Goodin	MDU Pension Plan	26	1,053,138	—
	SISP I[1,3]	10	230,600	—
	SISP II[2,3]	10	889,654	—
	SISP II 2012 Upgrade[4]	3	68,534	—
	SISP II 2013 Upgrade[4]	2	936,419	—
	SISP Excess[5]	26	35,046	—
Doran N. Schwartz	MDU Pension Plan	4	103,247	—
	SISP II[2,3]	8	501,190	—
	SISP II 2013 Upgrade[4]	2	165,873	—
	SISP II 2014 Upgrade[4]	1	83,760	—
David C. Barney[6]	SISP II[2,3]	10	1,089,837	—
	SISP II 2014 Upgrade[4]	1	216,295	—
Jeffrey S. Thiede[6]	—	—	—	—
Patrick L. O'Bryan[6]	—	—	—	—
Steven L. Bietz	WBI Pension Plan	28	1,299,883	33,580
	SISP I[1,3]	10	846,479	—
	SISP II[2,3]	10	813,506	—
	SISP Excess[5]	28	169,124	10,433[7]

[1] Grandfathered under Section 409A.

[2] Not grandfathered under Section 409A.

[3] Years of credited service only affects vesting under SISP I and SISP II. The number of years of credited service in the table reflects the years of vesting service completed in SISP I and SISP II as of December 31, 2015, rather than total years of service with the company. Ten years of vesting service is required to obtain the full benefit under these plans. The present value of accumulated benefits was calculated by assuming the named executive officer would have ten years of vesting service on the assumed benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

[4] Benefit level increases granted under SISP II on or after January 1, 2010, require an additional three years of vesting service for the increase. Mr. Goodin received a benefit increase effective January 1, 2012, which has vested. Messrs. Goodin and Schwartz received benefit level increases effective January 1, 2013, and Messrs. Schwartz and Barney received a benefit level increase effective January 1, 2014; the present value of their accumulated benefits was calculated assuming that the additional vesting requirements would be met.

[5] The number of years of credited service under the SISP excess reflects the years of credited benefit service in the appropriate pension plan as of December 31, 2009, when the MDU and WBI pension plans were frozen, rather than the years of participation in the SISP excess. We reflect years of credited benefit service in the appropriate pension plan because the SISP excess provides a benefit that is based on benefits that would have been payable under the MDU and WBI pension plans absent Internal Revenue Code limitations.

[6] Messrs. Barney, Thiede, and O'Bryan are not eligible to participate in the pension plans. Messrs. Thiede and O'Bryan do not participate in the SISP.

[7] Payable for 2015 but deferred pursuant to Section 409A.

The amounts shown for the pension plan and SISP excess represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2015, calculated using a 3.76%, 3.96%, and 4.07% discount rate for the SISP excess, MDU pension plan, and WBI pension plan, respectively, the Society of Actuaries RP-2014 Adjusted to 2006 Total Dataset Mortality with Scale MP-2015 for post-retirement mortality, and no recognition of future salary increases or pre-retirement mortality. The assumed retirement age for these benefits was age 60 for Messrs. Goodin and Schwartz. This is the earliest age at which the executives could begin receiving unreduced benefits. Mr. Bietz's benefits reflect his actual termination date of July 17, 2015. The amounts shown for the SISP I and SISP II were determined using a 3.76% discount rate and assume benefits commenced at age 65.

Pension Plan

Messrs. Goodin and Schwartz participate in the MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees, which we refer to as the MDU pension plan. Mr. Bietz participates in the Williston Basin Interstate Pipeline Company Pension Plan, which we refer to as the WBI pension plan. Pension benefits under the pension plans are based on the participant's average annual salary over the 60 consecutive month period in which the participant received the highest annual salary during the participant's final 10 years of service. For this purpose, only a participant's salary is considered; incentives and other forms of compensation are not included. Benefits are determined by multiplying (1) the participant's years of credited service by (2) the sum of (a) the average annual salary up to the social security integration level times 1.1% and (b) the average annual salary over the social security integration level times 1.45%. The maximum years of service recognized when determining benefits under the pension plans is 35. Pension plan benefits are not reduced for social security benefits.

Both of the pension plans were amended to cease benefit accruals as of December 31, 2009, meaning the normal retirement benefit will not change. The years of credited service in the table reflect the named executive officers' years of credited service as of December 31, 2009.

To receive unreduced retirement benefits under the pension plans, participants must either remain employed until age 60 or elect to defer commencement of benefits until age 60. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service under the pension plans, are eligible for early retirement benefits. Early retirement benefits are determined by reducing the normal retirement benefit by 0.25% per month for each month before age 60. If a participant's employment terminates before age 55, the same reduction applies for each month the termination occurs before age 62, with the reduction capped at 21%.

Benefits for single participants under the pension plans are paid as straight life annuities, and benefits for married participants are paid as actuarially reduced annuities with a survivor benefit for spouses, unless participants choose otherwise. Participants hired before January 1, 2004, who terminate employment before age 55, may elect to receive their benefits in a lump sum. Mr. Goodin would have been eligible for a lump sum if he had retired on December 31, 2015.

The Internal Revenue Code limits the amounts paid under the pension plans and the amount of compensation recognized when determining benefits. In 2009, when the pension plans were frozen, the maximum annual benefit payable under the pension plans was $195,000 and the maximum amount of compensation recognized when determining benefits was $245,000.

Supplemental Income Security Plan

We also offer select key managers and executives benefits under our defined benefit nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. Messrs. Goodin, Schwartz, Barney, and Bietz participate in the SISP. Benefits under the SISP consist of:

- a supplemental retirement benefit intended to augment the retirement income provided under the pension plans – we refer to this benefit as the regular SISP benefit
- an excess retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans – we refer to this benefit as the SISP excess benefit and
- death benefits – we refer to these benefits as the SISP death benefit.

SISP benefits are forfeited if the participant's employment is terminated for cause.

Regular SISP Benefits and Death Benefits

Regular SISP benefits and death benefits are determined by reference to one of two schedules attached to the SISP – the original schedule or the amended schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedules. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary. Benefit levels in the amended schedule, which became effective on January 1, 2010, are 20% lower than the benefit levels in the original schedule. The amended schedule applies to new participants and participants who receive a benefit level increase on or after January 1, 2010. None of the named executive officers received a benefit level increase on or after January 1, 2015. Effective February 11, 2016, the SISP was amended to freeze the plan to new participants and to current participants at their current benefit levels.

Participants can elect to receive (1) the regular SISP benefit only, (2) the SISP death benefit only, or (3) a combination of both. Regardless of the participant's election, if the participant dies before the regular SISP benefit would commence, only the SISP death benefit is provided. If the participant elects to receive both a regular SISP benefit and a SISP death benefit, each of the benefits is reduced proportionately.

The regular SISP benefits reflected in the table above are based on the assumption that the participant elects to receive only the regular SISP benefit. The present values of the SISP death benefits that would be provided if the named executive officers had died on December 31, 2015, prior to the commencement of regular SISP benefits, are reflected in the table that appears in the section entitled "Potential Payments upon Termination or Change of Control."

Regular SISP benefits that were vested as of December 31, 2004, and were grandfathered under Section 409A of the Internal Revenue Code remain subject to SISP provisions then in effect, which we refer to as SISP I benefits. Regular SISP benefits that are subject to Section 409A of the Internal Revenue Code, which we refer to as SISP II benefits, are governed by amended provisions intended to comply with Section 409A. Participants generally have more discretion with respect to the distributions of their SISP I benefits.

The time and manner in which the regular SISP benefits are paid depend on a variety of factors, including the time and form of benefit elected by the participant and whether the benefits are SISP I or SISP II benefits. Unless the participant elects otherwise, the SISP I benefits are paid over 180 months, with benefits commencing when the participant attains age 65 or, if later, when the participant retires. The SISP II benefits commence when the participant attains age 65 or, if later, when the participant retires, subject to a six-month delay if the participant is subject to the provisions of Section 409A of the Internal Revenue Code that require delayed commencement of these types of retirement benefits. The SISP II benefits are paid over 180 months or, if commencement of payments is delayed for six months, 173 months. If the commencement of benefits is delayed for six months, the first payment includes the payments that would have been paid during the six-month period plus interest equal to one-half of the annual prime interest rate on the participant's last date of employment. If the participant dies after the regular SISP benefits have begun but before receipt of all of the regular SISP benefits, the remaining payments are made to the participant's designated beneficiary.

Rather than receiving their regular SISP I benefits in equal monthly installments over 15 years commencing at age 65, participants can elect a different form and time of commencement of their SISP I benefits. Participants can elect to defer commencement of the regular SISP I benefits. If this is elected, the participant retains the right to receive a monthly SISP death benefit if death occurs prior to the commencement of the regular SISP I benefit.

Participants also can elect to receive their SISP I benefits in one of three actuarially equivalent forms – a life annuity, 100% joint and survivor annuity, or a joint and two-thirds joint and survivor annuity, provided that the cost of providing these actuarial equivalent forms of benefits does not exceed the cost of providing the normal form of benefit. Neither the election to receive an actuarially equivalent benefit nor the administrator's right to pay the regular SISP benefit in the form of an actuarially equivalent lump sum are available with respect to SISP II benefits.

To promote retention, the regular SISP benefits are subject to the following 10-year vesting schedule:

- 0% vesting for less than 3 years of participation
- 20% vesting for 3 years of participation
- 40% vesting for 4 years of participation and
- an additional 10% vesting for each additional year of participation up to 100% vesting for 10 years of participation.

There is an additional vesting requirement on benefit level increases for the regular SISP benefit granted on or after January 1, 2010. The requirement applies only to the increased benefit level. The increased benefit vests after the later of three additional years of participation in the SISP or the end of the regular vesting schedule described above. The additional three-year vesting requirement for benefit level increases is prorated for participants who are officers, attain age 65, and, pursuant to the company's bylaws, are required to retire prior to the end of the additional vesting period as follows:

- 33% of the increase vests for participants required to retire at least one year but less than two years after the increase is granted and
- 66% of the increase vests for participants required to retire at least two years but less than three years after the increase is granted.

The benefit level increases of participants who attain age 65 and are required to retire pursuant to the company's bylaws will be further reduced to the extent the participants are not fully vested in their regular SISP benefit under the 10-year vesting schedule described above. The additional vesting period associated with a benefit level increase may be waived by the compensation committee.

SISP death benefits become fully vested if the participant dies while actively employed. Otherwise, the SISP death benefits are subject to the same vesting schedules as the regular SISP benefits.

The SISP also provides that if a participant becomes totally disabled, the participant will continue to receive service credit for up to two additional years under the SISP as long as the participant is totally disabled during such time. Since the named executive officers other than Messrs. Goodin and Barney, in their upgrades, and Mr. Schwartz, are fully vested in their SISP benefits, this would not result in any incremental benefit for the named executive officers other than Messrs. Goodin, Schwartz, and Barney. The present value of these additional years of service for Messrs. Goodin, Schwartz, and Barney is reflected in the table in "Potential Payments upon Termination or Change of Control" below.

SISP Excess Benefits

SISP excess benefits are equal to the difference between (1) the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and (2) the actual benefits payable to the participant under the pension plans. Participants are only eligible for the SISP excess benefits if (1) the participant is fully vested under the pension plan, (2) the participant's employment terminates prior to age 65, and (3) benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation. Effective January 1, 2005, participants who were not then vested in the SISP excess benefits were also required to remain actively employed by the company until age 60. In 2009, the plan was amended to limit eligibility for the SISP excess benefit to current SISP participants (1) who were already vested in the SISP excess benefit or (2) who would become vested in the SISP excess benefits if they remain employed with the company until age 60. The plan was further amended to freeze the SISP excess benefits to a maximum of the benefit level payable based on the participant's years of service and compensation level as of December 31, 2009. Mr. Goodin must remain employed until age 60 to become entitled to his SISP excess benefit. Mr. Bietz is entitled to the SISP excess benefit even though he terminated employment prior to age 65. Messrs. Schwartz, Barney, Thiede, and O'Bryan are not eligible for this benefit.

Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65. If a participant who dies prior to age 65 elected a joint and survivor benefit, the survivor's SISP excess benefit is paid until the date the participant would have attained age 65.

Nonqualified Deferred Compensation for 2015

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
David L. Goodin	—	—	—	—	—
Doran N. Schwartz	—	—	—	—	—
David C. Barney	—	—	—	—	—
Jeffrey S. Thiede	—	150,000	(955)	—	268,885 [1]
Patrick L. O'Bryan	—	—	—	—	—
Steven L. Bietz	—	—	—	—	—

[1] Includes $150,000 which was awarded to Mr. Thiede under the Nonqualified Defined Contribution Plan for 2015, $75,000 for 2014, and $33,000 for 2013. Each of these amounts is reported in column (i) of the Summary Compensation Table in this proxy statement for its respective year.

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, effective January 1, 2012, to provide deferred compensation for a select group of management or highly compensated employees who do not participate in the SISP. The compensation committee determines the amount of employer contributions under the Nonqualified Defined Contribution Plan, which are credited to plan accounts and not funded. After satisfying a four-year vesting requirement for each contribution, the contributions and investment earnings will be distributed to the executive in a lump sum upon separation from service with the company or in annual installments commencing upon the later of (i) separation from service and (ii) age 65. Plan benefits become fully vested if the participant dies while actively employed. Benefits are forfeited if the participant's employment is terminated for cause.

Deferral of Annual Incentive Compensation

Participants in the executive incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2015 was 4.66% or the "Moody's Rate," which is the average of (i) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield

Average for "A" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12 and (ii) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "Baa" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was granted. The amounts will be paid in accordance with the participant's election in a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts become immediately payable.

A change of control for purposes of Deferred Annual Incentive Compensation is defined as:

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors or
- acquisition of our assets having a gross fair market value at least equal to 40% of the total gross fair market value of all of our assets.

Potential Payments upon Termination or Change of Control

The following tables show the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios and upon a change of control. For the named executive officers, other than Mr. Bietz, the information assumes the terminations and the change of control occurred on December 31, 2015. For Mr. Bietz, the information relates to his actual retirement on July 17, 2015, and assumes that a change of control occurred on December 31, 2015. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables exclude compensation and benefits provided under plans or arrangements that do not discriminate in favor of the named executive officers and that are generally available to all salaried employees, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables include amounts under the Nonqualified Defined Contribution Plan, but do not include the named executive officers' deferred annual incentive compensation. See the Pension Benefits for 2015 table and the Nonqualified Deferred Compensation for 2015 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans, the Nonqualified Defined Contribution Plan, and their deferred annual incentive compensation.

The calculation of the present value of excess SISP benefits our named executive officers would be entitled to upon termination of employment under the SISP was computed based on calculations assuming an age rounded to the nearest whole year of age. Actual payments may differ. The terms of the excess SISP benefit are described following the Pension Benefits for 2015 table.

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a cap on the amount of base salary taken into account when calculating benefits. For officers, the limit on base salary is $200,000. For other salaried employees, the limit is $100,000. For all salaried employees, disability payments continue until age 65 if disability occurs at or before age 60 and for 5 years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The amounts in the tables reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits.

Upon a change of control, share-based awards granted under our Long-Term Performance-Based Incentive Plan vest and non-share-based awards are paid in cash. All performance share awards for Messrs. Goodin, Schwartz, Barney, Thiede, and Bietz and the annual incentives for Messrs. Goodin, Barney, Thiede, and O'Bryan which were awarded under the Long-Term Performance-Based Incentive Plan, would vest at their target levels. For this purpose, the term "change of control" is defined as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock
- a change in a majority of our board of directors since April 22, 1997, without the approval of a majority of the board members as of April 22, 1997, or whose election was approved by such board members
- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common

stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors or

- stockholder approval of our liquidation or dissolution.

Performance share awards will be forfeited if the participant's employment terminates for any reason before the participant has reached age 55 and completed 10 years of service. Performance shares and related dividend equivalents for those participants whose employment is terminated other than for cause after the participant has reached age 55 and completed 10 years of service will be prorated as follows:

- if the termination of employment occurs during the first year of the performance period, the shares are forfeited

- if the termination of employment occurs during the second year of the performance period, the executive receives a prorated portion of any performance shares earned based on the number of months employed during the performance period and

- if the termination of employment occurs during the third year of the performance period, the executive receives the full amount of any performance shares earned.

As of December 31, 2015, Messrs. Goodin, Schwartz, and Thiede had not satisfied this age and years of service requirement. Accordingly, if a December 31, 2015 termination other than for cause without a change of control is assumed, the named executive officers' 2015-2017 performance share awards would be forfeited; any amounts earned under the 2014-2016 performance share award for Mr. Barney would be reduced by one-third and for Mr. Bietz by 17/36 and such awards for Messrs. Goodin, Schwartz, and Thiede would be forfeited; and any amounts earned under the 2013-2015 performance share award for Mr. Bietz would not be reduced and the awards for Messrs. Goodin and Schwartz would be forfeited. Messrs. Barney and Thiede had no 2013-2015 performance share awards, and Mr. O'Bryan had no 2015-2017, 2014-2016, or 2013-2015 performance share awards. The number of performance shares earned following a termination depends on actual performance through the full performance period. As actual performance for the 2013-2015 performance share awards has been determined, the amounts for these awards in the event of a termination without a change of control were based on actual performance, which resulted in vesting of 31% of the target award. For the 2014-2016 performance share awards, because we do not know what actual performance through the entire performance period will be, we have assumed target performance will be achieved and, therefore, show two-thirds of the target award, except for Mr. Bietz, which shows 19/36 of the target award. No amounts are shown for the 2015-2017 performance share awards because such awards would be forfeited. Although vesting would only occur after completion of the performance period, the amounts shown in the tables were not reduced to reflect the present value of the performance shares that could vest. Dividend equivalents attributable to earned performance shares would also be paid. Dividend equivalents accrued through December 31, 2015, are included in the amounts shown, except for Mr. Bietz which are accrued through his retirement date.

The value of the vesting of performance shares shown in the tables was determined by multiplying the number of performance shares that would vest due to termination or a change of control by the closing price of our stock on December 31, 2015.

The compensation committee may consider providing severance benefits on a case-by-case basis for employment terminations. The compensation committee adopted a checklist of factors in February 2005 to consider when determining whether any such severance benefits should be paid. Except for Mr. Bietz, the tables do not reflect any such severance benefits, as these benefits are made in the discretion of the committee on a case-by-case basis and it is not possible to estimate the severance benefits, if any, that would be paid.

David L. Goodin

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:						
Short-term Incentive[1]					755,000	755,000
2013-2015 Performance Shares					875,656	875,656
2014-2016 Performance Shares					665,794	665,794
2015-2017 Performance Shares					1,375,085	1,375,085
Benefits and Perquisites:						
Regular SISP[2]	1,186,624	1,186,624		2,121,340	1,186,624	
SISP Death Benefits[3]			6,351,958			
Disability Benefits[4]				13,821		
Total	**1,186,624**	**1,186,624**	**6,351,958**	**2,135,161**	**4,858,159**	**3,671,535**

1 Represents the target 2015 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

2 Represents the present value of Mr. Goodin's vested regular SISP benefit as of December 31, 2015, which was $12,888 per month for 15 years, commencing at age 65. Present value was determined using a 3.76% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2015 table. The amount payable for a disability reflects a credit for one additional year of vesting, which would result in full vesting of the 2013 SISP upgrade.

3 Represents the present value of 180 monthly payments of $46,080 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.76% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2015 table.

4 Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 3.96% discount rate.

Doran N. Schwartz

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:						
2013-2015 Performance Shares					241,671	241,671
2014-2016 Performance Shares					174,945	174,945
2015-2017 Performance Shares					276,831	276,831
Benefits and Perquisites:						
Regular SISP[1]	401,962	401,962		752,715	401,962	
SISP Death Benefits[2]			3,014,975			
Disability Benefits[3]				736,474		
Total	**401,962**	**401,962**	**3,014,975**	**1,489,189**	**1,095,409**	**693,447**

1 Represents the present value of Mr. Schwartz's vested regular SISP benefit as of December 31, 2015, which was $5,840 per month for 15 years, commencing at age 65. Present value was determined using a 3.76% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2015 table. The amount payable for a disability reflects a credit for two additional years of vesting, which would result in full vesting of the 2013 and 2014 SISP upgrades.

2 Represents the present value of 180 monthly payments of $21,872 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.76% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2015 table.

3 Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 3.96% discount rate.

David C. Barney

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:						
Short-term Incentive[1]					150,000	150,000
2013-2015 Performance Shares						
2014-2016 Performance Shares	98,474	98,474	98,474	98,474	147,721	147,721
2015-2017 Performance Shares					223,801	223,801
Benefits and Perquisites:						
Regular SISP[2]	1,075,709	1,075,709		1,289,201	1,075,709	
SISP Death Benefits[3]			3,014,975			
Disability Benefits[4]				273,954		
Total	**1,174,183**	**1,174,183**	**3,113,449**	**1,661,629**	**1,597,231**	**521,522**

1 Represents the target 2015 additional annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

2 Represents the present value of Mr. Barney's vested regular SISP benefit as of December 31, 2015, which was $9,125 per month for 15 years, commencing at age 65. Present value was determined using a 3.76% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2015 table. The amount payable for a disability reflects a credit for two additional years of vesting, which would result in full vesting of the 2014 SISP upgrade.

3 Represents the present value of 180 monthly payments of $21,872 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.76% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2015 table.

4 Represents the present value of the disability benefit. Present value was determined using the 3.76% discount rate applied for purposes of the SISP calculations.

Jeffrey S. Thiede

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:						
Short-term Incentive[1]					340,000	340,000
2013-2015 Performance Shares						
2014-2016 Performance Shares					155,511	155,511
2015-2017 Performance Shares					240,817	240,817
Benefits and Perquisites:						
Nonqualified Defined Contribution Plan Death Benefit[2]			268,885			
Disability Benefits[3]				541,543		
Total			**268,885**	**541,543**	**736,328**	**736,328**

1 Represents the target 2015 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

2 Represents the value of Mr. Thiede's unvested Nonqualified Defined Contribution Plan account at December 31, 2015, which would be paid upon death.

3 Represents the present value of the disability benefit. Present value was determined using the 3.76% discount rate applied for purposes of the SISP calculations. Though Mr. Thiede is not a participant in the SISP, this rate is considered reasonable for purposes of this calculation as it would be applied if Mr. Thiede were a SISP participant.

Patrick L. O'Bryan

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:						
Short-term Incentive[1]					900,000	900,000
Retention Incentive	150,000	150,000	150,000	150,000	150,000	150,000
Benefits and Perquisites:						
Disability Benefits[2]				524,844		
Total	**150,000**	**150,000**	**150,000**	**674,844**	**1,050,000**	**1,050,000**

[1] Represents the target 2015 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

[2] Represents the present value of the disability benefit. Present value was determined using the 3.76% discount rate applied for purposes of the SISP calculations. Though Mr. O'Bryan is not a participant in the SISP, this rate is considered reasonable for purposes of this calculation as it would be applied if Mr. O'Bryan were a SISP participant.

Steven L. Bietz

Executive Benefits and Payments Upon Termination or Change of Control[1]	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control ($)
Compensation:					
2013-2015 Performance Shares	94,085				309,103
2014-2016 Performance Shares	114,770				221,602
2015-2017 Performance Shares					287,750
Total	**208,855**				**818,455**

[1] Mr. Bietz retired on July 17, 2015. The information in this table relates to his actual retirement effective July 17, 2015, and assumes that a change of control occurred on December 31, 2015. The amount shown under Voluntary Termination for the 2013-2015 Performance Shares is based on actual performance, resulting in payment of 31% of the target award. The amount shown under Voluntary Termination for the 2014-2016 Performance Shares is the target award, prorated based on the number of months Mr. Bietz worked during the performance period. The amounts shown under Change of Control are the target awards for the entire performance period. His termination qualified as an early retirement under our qualified pension plan and our SISP. These plans and Mr. Bietz's benefits under them are described in the Pension Benefits for 2015 table and accompanying narratives. Mr. Bietz was paid a lump-sum payment of $750,000, less applicable tax withholding amounts, for the entry into a waiver and voluntary release agreement and in recognition of his 34 years of service.

Director Compensation for 2015

Name[1] (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($) (c)[2]	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation ($) (g)[3]	Total ($) (h)
Thomas Everist	75,000	110,000	—	—	—	156	185,156
Karen B. Fagg	75,000	110,000	—	—	—	656	185,656
Mark A. Hellerstein	65,000	110,000	—	—	—	156	175,156
A. Bart Holaday	65,000	110,000	—	—	—	156	175,156
Dennis W. Johnson	80,000	110,000	—	—	—	156	190,156
William E. McCracken	65,000	110,000	—	—	—	156	175,156
Patricia L. Moss	65,000	110,000	—	—	—	156	175,156
Harry J. Pearce	155,000	110,000	—	—	—	156	265,156
John K. Wilson	65,000 [4]	110,000	—	—	—	156	175,156

[1] J. Kent Wells, who resigned as vice chairman of MDU Resources Group, Inc., chief executive officer of Fidelity Exploration & Production Company and a director of MDU Resources Group, Inc. effective February 28, 2015, did not receive any additional compensation for services provided as a director.

[2] Reflects the aggregate grant date fair value of 6,039 shares of MDU Resources Group, Inc. stock purchased for our non-employee directors measured in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock based compensation in FASB Accounting Standards Codification Topic 718. The grant date fair value is based on the purchase price of our common stock on the grant date on November 18, 2015, which was $18.212. The $17.73 in cash paid to each director for the fractional shares is included in the amounts reported in column (c) to this table.

[3] Group life insurance premium and a matching charitable contribution of $500 for Ms. Fagg.

[4] Includes $64,991 that Mr. Wilson received in our common stock in lieu of cash.

The following table shows the cash and stock retainers payable to our non-employee directors.

Base Retainer	$ 65,000
Additional Retainers:	
Non-Executive Chairman	90,000
Lead Director, if any	33,000
Audit Committee Chairman	15,000
Compensation Committee Chairman	10,000
Nominating and Governance Committee Chairman	10,000
Annual Stock Grant[1]	110,000

[1] The annual stock grant is a grant of shares equal in value to $110,000.

There are no meeting fees.

In addition to liability insurance, we maintain group life insurance in the amount of $100,000 on each non-employee director for the benefit of each director's beneficiaries during the time each director serves on the board. The annual cost per director is $156.

Directors may defer all or any portion of the annual cash retainer and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

Directors are reimbursed for all reasonable travel expenses including spousal expenses in connection with attendance at meetings of the board and its committees. All amounts together with any other perquisites were below the disclosure threshold for 2015.

Our post-retirement income plan for directors was terminated in May 2001 for current and future directors. The net present value of each director's benefit was calculated and converted into phantom stock. Payment is deferred pursuant to the Deferred Compensation Plan for Directors and will be made in cash over a five-year period after the director's retirement from the board.

Our director stock ownership policy contained in our corporate governance guidelines requires each director to own our common stock equal in value to five times the director's annual cash base retainer. Shares acquired through purchases on the open market and participation in our director stock plans will be considered in ownership calculations as will ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of that director's initial election to the board to meet the requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. For stock ownership, please see "Security Ownership."

Narrative Disclosure of our Compensation Policies and Practices as They Relate to Risk Management

The human resources department has conducted an assessment of the risks arising from our compensation policies and practices for all employees and concluded that none of these risks is reasonably likely to have a material adverse effect on the company. Based on the human resources department's assessment and taking into account information received from the risk identification process, senior management and our management policy committee concluded that risks arising from our compensation policies and practices for all employees are not reasonably likely to have a material adverse effect on the company. After review and discussion with senior management, the compensation committee concurred with this assessment.

As part of its assessment of the risks arising from our compensation policies and practices for all employees, the human resources department identified the principal areas of risk faced by the company that may be affected by our compensation policies and practices for all employees, including any risks resulting from our operating businesses' compensation policies and practices. In assessing the risks arising from our compensation policies and practices, the human resources department identified the following practices designed to prevent excessive risk taking:

Business management and governance practices

- risk management is a specific performance competency included in the annual performance assessment of Section 16 officers
- board oversight on capital expenditure and operating plans that promotes careful consideration of financial assumptions
- limitation on business acquisitions without board approval
- employee integrity training programs and anonymous reporting systems
- quarterly risk assessment reports at audit committee meetings and
- prohibitions on holding company stock in an account that is subject to a margin call, pledging company stock as collateral for a loan, and hedging of company stock by Section 16 officers and directors.

Executive compensation practices

- active compensation committee review of executive compensation, including comparison of executive compensation to total stockholder return ratio to the ratio for the performance graph peer group (PEER Analysis)
- the initial determination of a position's salary grade to be at or near the 50th percentile of base salaries paid to similar positions at peer group companies and/or relevant industry companies
- consideration of peer group and/or relevant industry practices to establish appropriate compensation target amounts
- a balanced compensation mix of fixed salary and annual and long-term incentives tied to the company's financial performance
- use of interpolation for annual and long-term incentive awards to avoid payout cliffs
- negative discretion to adjust any annual or long-term incentive award payment downward
- use of caps on annual incentive awards (maximum of 200% of target) and long-term incentive stock grant awards (200% target)
- clawback availability on incentive payments in the event of a financial restatement
- use of performance shares, rather than stock options or stock appreciation rights, as the equity component of incentive compensation

- use of performance shares with a relative total stockholder return performance goal and mandatory reduction in award if total stockholder return is negative
- use of three-year performance periods to discourage short-term risk-taking
- substantive incentive goals measured primarily by return on invested capital, earnings, and earnings per share criteria, which encourage balanced performance and are important to stockholders
- use of financial performance metrics that are readily monitored and reviewed
- regular review of the appropriateness of the companies in the performance graph peer group
- stock ownership requirements for the board and for executives receiving long-term incentive awards under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan
- mandatory holding periods for 50% of any net after-tax shares earned under long-term incentive awards granted in 2011 and thereafter and
- use of independent consultants in establishing pay targets at least biennially.

INFORMATION CONCERNING EXECUTIVE OFFICERS

At the first annual meeting of the board after the annual meeting of stockholders, our board of directors elects our executive officers, who serve until their successors are chosen and qualify. A majority of our board of directors may remove any executive officer at any time. Information concerning our executive officers, including their ages as of December 31, 2015, present corporate positions, and business experience, is as follows:

Name	Age	Present Corporate Position and Business Experience
David L. Goodin	54	Mr. Goodin was elected president and chief executive officer of the company and a director effective January 4, 2013. For more information about Mr. Goodin, see "Item 1. Election of Directors."
David C. Barney	60	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013; president effective January 1, 2012; and president of its western area operations effective October 2008. Prior to that, he was manager of its Northern California region effective July 2005 and became president of Concrete, Inc. in 1996. He joined Concrete, Inc. in 1986 and held numerous positions of increasing responsibility before it was acquired by Knife River Corporation in September 1993.
Martin A. Fritz	51	Mr. Fritz was elected president and chief executive officer of WBI Holdings, Inc. effective July 20, 2015. Prior to joining WBI Holdings, Inc., he had his own energy consulting firm, Fritz Consulting, from February 2014 to July 2015, where he provided strategy, operations, business development, and business brokerage services. Prior to that, Mr. Fritz was employed by EQT Corporation in positions of increasing responsibility, most recently serving as its executive vice president midstream operations, land and construction from 2013 through January 2014 and vice president EQT and president EQT midstream operations from 2008 to 2013.
Dennis L. Haider	63	Mr. Haider was elected executive vice president-business development effective June 1, 2013. Prior to that, he was executive vice president-business development and gas supply of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company from January 1, 2012 to May 31, 2013; executive vice president-regulatory, gas supply, and business development of Cascade Natural Gas Corporation and Intermountain Gas Company from October 1, 2010 to December 31, 2011, and of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. from October 1, 2008 to December 31, 2011; and executive vice president-business development and gas supply of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. from August 1, 2005 to September 30, 2008. He joined Montana-Dakota Utilities Co. in 1978 and held numerous positions of increasing responsibility.
Anne M. Jones	52	Ms. Jones was elected vice president-human resources effective January 1, 2016. Prior to that, she was vice president-human resources, customer service, and safety at Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective July 1, 2013; director of human resources for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective June 2008; and manager of organizational learning and development effective February 2003. Ms. Jones joined Montana-Dakota Utilities Co. in 1982 and held numerous positions of increasing responsibility.
Nicole A. Kivisto	42	Ms. Kivisto was elected president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 9, 2015. Prior to that, she was vice president of operations for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective January 3, 2014; vice president, controller and chief accounting officer for the company effective February 17, 2010; controller effective December 1, 2005; financial analyst IV in the Corporate Planning Department effective May 2003; financial and investor relations analyst in the Investor Relations Department effective May 2000; and financial analyst in the Corporate Accounting Department effective July 1995.
Daniel S. Kuntz	62	Mr. Kuntz was elected general counsel and secretary effective January 9, 2016. Mr. Kuntz joined the company in June 2004 as a senior attorney. He then became associate general counsel in April 2007 and added assistant secretary to his title in August 2007. Prior to joining the company, Mr. Kuntz was an associate and partner at Zuger, Kirmis & Smith Law firm.

Cynthia J. Norland	61	Ms. Norland was elected vice president-administration effective July 16, 2007. Prior to that, she was the assistant vice president-administration effective January 17, 2007; associate general counsel in the Legal Department effective March 6, 2004; and senior attorney in the Legal Department effective June 1, 1995.
Nathan W. Ring	40	Mr. Ring was elected vice president, controller and chief accounting officer effective January 3, 2014. Prior to that, he was treasurer and controller for MDU Construction Services Group, Inc. since September 2012 and was its controller from June 2012 until September 2012. Prior to that, he served as assistant controller of D S S Company, a subsidiary of Knife River Corporation, from March 2009 to June 2012 and as controller of another Knife River Corporation subsidiary, Hap Taylor & Sons, Inc. doing business as Norm's Utility Contractor, Inc., from March 2007 to March 2009. He joined MDU Resources Group, Inc. in 2001 as a tax analyst.
Doran N. Schwartz	46	Mr. Schwartz was elected vice president and chief financial officer effective February 17, 2010. Prior to that, he was vice president and chief accounting officer effective March 1, 2006; and assistant vice president-special projects effective September 6, 2005. He was director of membership rewards for American Express, a financial services company, from November 2004 to August 1, 2005; audit manager for Deloitte & Touche, an audit and professional services company, from June 2002 to November 2004; and audit manager/senior for Arthur Andersen, an audit and professional services company, from December 1997 to June 2002.
Jeffrey S. Thiede	53	Mr. Thiede was elected president and chief executive officer of MDU Construction Services Group, Inc. effective April 30, 2013, and president effective January 1, 2012. Prior to that, he was president of Capital Electric Construction Company, Inc. effective July 2006, and president of Oregon Electric Construction, Inc. effective October 2004. Prior to joining the company, Mr. Thiede was a project director for DPR Construction and worked in the field as an inside wireman.
Jason L. Vollmer	38	Mr. Vollmer was elected treasurer and director of cash and risk management effective November 29, 2014. Mr. Vollmer joined the company effective October 17, 2005, as a financial analyst II. He then became financial analyst III effective January 1, 2007, and financial analyst IV effective February 2, 2009. Effective April 11, 2011, he became manager of treasury services, cash and risk management until June 30, 2014 when he became assistant treasurer of Centennial Energy Holdings, Inc. and manager of treasury services and risk management.

SECURITY OWNERSHIP

The table below sets forth the number of shares of our capital stock that each director and each nominee for director, each named executive officer, and all directors and executive officers as a group owned beneficially as of December 31, 2015.

Name	Common Shares Beneficially Owned[1]	Shares Held by Family Members[2]	Percent of Class	Deferred Director Fees Held as Phantom Stock[3]
David C. Barney	8,338 [4,5]	687	*	
Steven L. Bietz	73,849 [5,6]	565	*	
Thomas Everist	1,149,572 [7]		*	31,952
Karen B. Fagg	55,465		*	
David L. Goodin	73,462 [5,8]	8,859	*	
Mark A. Hellerstein	11,880		*	5,691
A. Bart Holaday	57,025		*	5,691
Dennis W. Johnson	74,511 [9]	163	*	
William E. McCracken	11,880		*	
Patricia L. Moss	75,957		*	
Patrick O'Bryan	—			
Harry J. Pearce	231,999		*	52,536
Doran N. Schwartz	46,496 [5,10]	1,300	*	
Jeffrey S. Thiede	2,580 [5]		*	
John K. Wilson	112,786		*	
All directors and executive officers as a group (23 in number)	2,186,977	12,828	1.1	95,870

* Less than one percent of the class.

1 "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security, or investment power with respect to a security.

2 These shares are included in the "Common Shares Beneficially Owned" column.

3 These shares are not included in the "Common Shares Beneficially Owned" column. Directors may defer all or a portion of their cash compensation pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

4 The total includes 687 shares owned by Mr. Barney's wife.

5 Includes full shares allocated to the officer's account in our 401(k) retirement plan.

6 Mr. Bietz disclaims all beneficial ownership of the 565 shares owned by his father.

7 Includes 1,070,000 shares of common stock acquired through the sale of Connolly-Pacific to us.

8 The total includes 8,859 shares owned by Mr. Goodin's wife.

9 Mr. Johnson disclaims all beneficial ownership of the 163 shares owned by his wife.

10 The total includes 1,300 shares owned by Mr. Schwartz's wife.

We prohibit our directors and executive officers from hedging their ownership of company common stock. They may not enter into transactions that allow them to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Directors, executive officers, and related persons are prohibited from holding our common stock in a margin account, with certain exceptions, or pledging company securities as collateral for a loan. Company common stock may be held in a margin brokerage account only if the stock is explicitly excluded from any margin, pledge, or security provisions of the customer agreement. Company common stock may be held in a cash account, which is a brokerage account that does not allow any extension of credit on securities. "Related person" means an executive officer's or director's spouse, minor child, and any person (other than a tenant or domestic employee) sharing the household of a director or executive officer, as well as any entities over which a director or executive officer exercises control.

The table below sets forth information with respect to any person we know to be the beneficial owner of more than five percent of any class of our voting securities.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	BlackRock, Inc. 55 East 52nd Street New York, NY 10055	13,972,978 [1]	7.20%
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	13,969,067 [2]	7.20%
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	13,816,559 [3]	7.07%
Common Stock	Parnassus Investments 1 Market Street, Suite 1600 San Francisco, CA 94105	13,664,457 [4]	7.00%

[1] In a Schedule 13G, Amendment No. 6, filed on January 26, 2016, BlackRock, Inc. reported sole voting power with respect to 13,000,204 shares and sole dispositive power with respect to 13,972,978 shares as the parent holding company or control person of BlackRock Advisors (UK) Limited, BlackRock Advisors, LLC, BlackRock Asset Management Canada Limited, BlackRock Asset Management Ireland Limited, BlackRock Asset Management North Asia Limited, BlackRock Asset Management Schweiz AG, BlackRock Financial Management, Inc., BlackRock Fund Advisors, BlackRock Fund Managers Ltd, BlackRock Institutional Trust Company, N.A., BlackRock Investment Management (Australia) Limited, BlackRock Investment Management (UK) Ltd, BlackRock Investment Management, LLC, and BlackRock Life Limited.

[2] In a Schedule 13G, filed on February 16, 2016, State Street Corporation reported shared voting and dispositive power with respect to all shares as the parent holding company or control person of State Street Global Advisors France, S.A., State Street Bank and Trust Company, SSGA Funds Management, Inc., State Street Global Advisors Limited, State Street Global Advisors, Ltd., State Street Global Advisors, Australia, Limited, State Street Global Advisors (Japan) Co., Ltd., and State Street Global Advisors (Asia) Limited.

[3] In a Schedule 13G, Amendment No. 3, filed on February 10, 2016, The Vanguard Group reported sole dispositive power with respect to 13,678,506 shares, shared dispositive power with respect to 138,053 shares, sole voting power with respect to 138,853 shares, and shared voting power with respect to 10,000 shares. These shares include 128,053 shares beneficially owned by Vanguard Fiduciary Trust Company, a wholly-owned subsidiary of The Vanguard Group, Inc., as a result of its serving as investment manager of collective trust accounts, and 20,800 shares beneficially owned by Vanguard Investments Australia, Ltd., a wholly-owned subsidiary of The Vanguard Group, Inc., as a result of its serving as investment manager of Australian investment offerings.

[4] In a Schedule 13G, Amendment No. 1, filed on February 12, 2016, Parnassus Investments reported sole voting and dispositive power with respect to all shares.

RELATED PERSON TRANSACTION DISCLOSURE

The board of directors has adopted a policy for the review of related person transactions. This policy is contained in our corporate governance guidelines, which are posted on our website at http://www.mdu.com/docs/default-source/governance/corporategovernanceguidelines.pdf. The audit committee reviews any transaction, arrangement or relationship, or series thereof:

- in which we are or will be a participant
- the amount involved exceeds $120,000 and
- a related person has or will have a material interest.

The purpose of this review is to determine whether this transaction is in the best interests of the company.

Related persons are directors, director nominees, executive officers, holders of 5% or more of our voting stock, and their immediate family members. Related persons are required promptly to report to our general counsel all proposed or existing related person transactions in which they are involved.

If our general counsel determines that the transaction may be required to be disclosed under the Securities and Exchange Commission's rules, the general counsel furnishes the information to the chairman of the audit committee. After its review, the committee makes a determination or a recommendation to the board and officers of the company with respect to the related person transaction. Upon receipt of the committee's recommendation, the board of directors or officers, as the case may be, take such action as they deem appropriate in light of their responsibilities under applicable laws and regulations.

CORPORATE GOVERNANCE

Director Independence

The board of directors has adopted guidelines on director independence that are included in our corporate governance guidelines, which are available for review on our corporate website at http://www.mdu.com/docs/default-source/governance/corporategovernanceguidelines.pdf. The board of directors has determined that current directors Thomas Everist, Karen B. Fagg, Mark A. Hellerstein, A. Bart Holaday, Dennis W. Johnson, William E. McCracken, Patricia L. Moss, Harry J. Pearce, and John K. Wilson:

- have no material relationship with us and
- are independent in accordance with our director independence guidelines and the New York Stock Exchange listing standards.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the independent directors and their immediate family members and affiliated entities on the one hand, and the company and its affiliates on the other, and in particular the following transactions, relationships, and arrangements:

- *Business relationships with entities with which a director is affiliated:* Agreements and/or payments between the City of Dickinson, North Dakota, where Dennis Johnson served as president of the city board of commissioners until his resignation effective October 31, 2015, and (i) Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy, Inc., an indirect wholly-owned subsidiary of the company, and Calumet Specialty Products Partners, L.P., relating to the supply of industrial water and treatment of waste water, (ii) Montana-Dakota Utilities Co. for utility services, and (iii) Knife River Corporation for street improvements and underground utilities.
- *Charitable contributions by the MDU Resources Foundation (Foundation) to nonprofit organizations, where a director, or a director's spouse, serves or has served as a director, chair, or vice chair of the board of trustees, trustee or member of the organization or related entity:* Charitable contributions by the Foundation to Sanford Health Foundation, Billings Catholic Schools Foundation, the Denver Children's Advocacy Center, Community Resources Inc., the University of North Dakota Foundation, the University of Jamestown and its foundation, and the St. Charles Foundation. None of the contributions made to any of these nonprofit entities during the last three fiscal years exceeded in any single year the greater of $1 million or 2% of the relevant entity's consolidated gross revenues.

Director Resignation Upon Change of Job Responsibility

Our corporate governance guidelines require a director to tender his or her resignation after a material change in job responsibility. In 2015, no directors submitted resignations under this requirement.

Board Evaluation

Our corporate governance guidelines provide that the board of directors, in coordination with the nominating and governance committee, will annually review and evaluate the performance and functioning of the board and its committees. In 2015, the board engaged an external consultant to conduct the annual evaluation which included interviews with individual board members and considered various topics relating to the board and committees, including board composition and culture, strategy and performance measures, risk monitoring and crisis control, succession planning, and stakeholder involvement. The results of the evaluations were reviewed and discussed in executive sessions of the committees and the board of directors.

Code of Conduct

We have a code of conduct and ethics, which we refer to as the Leading With Integrity Guide, which applies to all employees, directors, and officers.

We intend to satisfy our disclosure obligations regarding:

- amendments to, or waivers of, any provision of the code of conduct that applies to our principal executive officer, principal financial officer, and principal accounting officer and that relates to any element of the code of ethics definition in Regulation S-K, Item 406(b) and
- waivers of the code of conduct for our directors or executive officers, as required by New York Stock Exchange listing standards

by posting such information on our website at http://www.mdu.com/docs/default-source/governance/leadingwithintegrity.pdf.

Board Leadership Structure and Board's Role in Risk Oversight

The board separated the positions of chairman of the board and chief executive officer in 2006 and elected Harry J. Pearce, a non-employee independent director, as its chairman. Separating these positions allows the chief executive officer to focus on the full-time job of running our business, while allowing the chairman of the board to lead the board in its fundamental role of providing advice to and independent oversight of management. The board believes this structure recognizes the time, effort, and energy the chief executive officer is required to devote to the position in the current business environment, as well as the commitment required to serve as the chairman, particularly as the board's oversight responsibilities continue to grow and demand more time and attention. The fundamental role of the board of directors is to provide oversight of the management of the company in good faith and in the best interests of the company and its stockholders. Having an independent chairman is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders. An independent chairman avoids the conflicts of interest that arise when the chairman and chief executive officer positions are combined and more effectively manages relationships between the board and the chief executive officer. An independent chairman is in a better position to encourage frank and lively discussions and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. Our bylaws and corporate governance guidelines require that our chairman be independent. The board believes that having separate positions and having an independent outside director serve as chairman is the appropriate leadership structure for the company and demonstrates our commitment to good corporate governance.

Risk is inherent with every business, and how well a business manages risk can ultimately determine its success. We face a number of risks, including economic risks, environmental and regulatory risks, and others, such as the impact of competition, weather conditions, limitations on our ability to pay dividends, pension plan obligations, cyber attacks or acts of terrorism, and our ability to sell all of the assets of our exploration and production business and potential liabilities relating to sold assets arising from events prior to sale. Management is responsible for the day-to-day management of risks the company faces, while the board, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate and functioning as designed.

The board believes establishing the right "tone at the top" and full and open communication between management and the board of directors are essential for effective risk management and oversight. Our chairman meets regularly with our president and chief executive officer and other senior officers to discuss strategy and risks facing the company. Senior management attends the quarterly board meetings and is available to address any questions or concerns raised by the board on risk management-related and any other matters. Each quarter, the board of directors receives presentations from senior management on strategic matters involving our operations. The board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

While the board is ultimately responsible for risk oversight at our company, our three board committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. The audit committee assists the board in fulfilling its oversight responsibilities with respect to risk management in a general manner and specifically in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements, and, in accordance with New York Stock Exchange requirements, discusses policies with respect to risk assessment and risk management and their adequacy and effectiveness. Risk assessment reports are regularly provided by management to the audit committee or the full board. This opens the opportunity for discussions about areas where the company may have material risk exposure, steps taken to manage such exposure, and the company's risk tolerance in relation to company strategy. The audit committee reports regularly to the board of directors on the company's management of risks in the audit committee's areas of responsibility. The compensation committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks arising from our compensation policies and programs. The nominating and governance committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks associated with board organization, membership and structure, succession planning for our directors and executive officers, and corporate governance.

Board Meetings and Committees

During 2015, the board of directors held 12 meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2015. Director attendance at our annual meeting of stockholders is left to the discretion of each director. Three directors attended our 2015 annual meeting of stockholders. In November 2015, the board of directors adopted a resolution that attendance at the annual meeting by each director is encouraged.

Harry J. Pearce was elected non-employee chairman of the board on August 17, 2006, and previously served as lead director from February 15, 2001 to August 17, 2006. He presides at the executive session of the non-employee directors held in connection with each regularly scheduled quarterly board of directors meeting. The non-employee directors also meet in executive session with the chief executive officer at each regularly scheduled quarterly board of directors meeting. All of our non-employee directors are independent directors.

The board has a standing audit committee, compensation committee, and nominating and governance committee. These committees are composed entirely of independent directors.

The audit, compensation, and nominating and governance committees have charters, which are available for review on our website at http://www.mdu.com/integrity/governance/board-charters-and-committees. Our corporate governance guidelines are available at http://www.mdu.com/docs/default-source/governance/corporategovernanceguidelines.pdf, and our Leading With Integrity Guide is also on our website at http://www.mdu.com/docs/default-source/governance/leadingwithintegrity.pdf.

Nominating and Governance Committee

The nominating and governance committee met three times during 2015. The committee members are Karen B. Fagg, chair, A. Bart Holaday, William E. McCracken, and Patricia L. Moss.

The nominating and governance committee provides recommendations to the board with respect to:

- board organization, membership, and function
- committee structure and membership
- succession planning for our executive management and directors and
- corporate governance guidelines applicable to us.

The nominating and governance committee assists the board in overseeing the management of risks in the committee's areas of responsibility.

The committee identifies individuals qualified to become directors and recommends to the board the nominees for director for the next annual meeting of stockholders. The committee also identifies and recommends to the board individuals qualified to become our principal officers and the nominees for membership on each board committee. The committee oversees the evaluation of the board and management.

In identifying nominees for director, the committee consults with board members, our management, consultants, and other individuals likely to possess an understanding of our business and knowledge concerning suitable director candidates.

Our corporate governance guidelines include our policy on consideration of director candidates recommended to us. We will consider candidates that our stockholders recommend. Stockholders may submit director candidate recommendations to the nominating and governance committee chairman in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. Please include the following information:

- the candidate's name, age, business address, residence address, and telephone number
- the candidate's principal occupation
- the class and number of shares of our stock owned by the candidate
- a description of the candidate's qualifications to be a director
- whether the candidate would be an independent director and
- any other information you believe is relevant with respect to the recommendation.

These guidelines provide information to stockholders who wish to recommend candidates for director for consideration by the nominating and governance committee. Stockholders who wish to actually nominate persons for election to our board at an annual meeting of stockholders must follow the procedures set forth in section 2.08 of our bylaws. You may obtain a copy of the bylaws by writing to the secretary of MDU Resources Group, Inc. at the address above. Our bylaws are also available on our website at http://www.mdu.com/integrity/governance/guidelines-and-bylaws. See also the section entitled "2017 Annual Meeting of Stockholders" later in the proxy statement.

There are no differences in the manner by which the committee evaluates director candidates recommended by stockholders and those recommended by other sources.

In evaluating director candidates, the committee considers an individual's:

- background, character, and experience, including experience relative to our company's lines of business
- skills and experience which complement the skills and experience of current board members
- success in the individual's chosen field of endeavor
- skill in the areas of accounting and financial management, banking, general management, human resources, marketing, operations, public affairs, law, technology, and operations abroad
- background in publicly traded companies
- geographic area of residence
- diversity of business and professional experience, skills, gender, and ethnic background, as appropriate in light of the current composition and needs of the board
- independence, including any affiliation or relationship with other groups, organizations, or entities and
- prior and future compliance with applicable law and all applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality, stock ownership and trading policies, and our other policies and guidelines.

In addition, our bylaws contain requirements that a person must meet in order to qualify for service as a director.

As indicated above, when identifying nominees to serve as director, the nominating and governance committee will consider candidates with diverse business and professional experience, skills, gender, and ethnic background, as appropriate, in light of the current composition and needs of the board. The nominating and governance committee assesses the effectiveness of this policy annually in connection with the nomination of directors for election at the annual meeting of stockholders. The composition of the current board reflects diversity in business and professional experience, skills, and gender.

The committee generally will hire an outside firm to perform a background check on potential nominees.

Audit Committee

The audit committee is a separately-designated standing committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

The audit committee met eight times during 2015. The audit committee members are Dennis W. Johnson, chair, Mark A. Hellerstein, A. Bart Holaday, and John K. Wilson. The board of directors has determined that Messrs. Johnson, Hellerstein, Holaday, and Wilson are "audit committee financial experts" as defined by Securities and Exchange Commission regulations and meet the independence standard for audit committee members under our director independence guidelines, the New York Stock Exchange listing standards, and Securities and Exchange Commission rules.

The audit committee assists the board of directors in fulfilling its oversight responsibilities to the stockholders and serves as a communication link among the board, management, the independent registered public accounting firm, and the internal auditors. The audit committee:

- assists the board's oversight of
  - the integrity of our financial statements and system of internal controls
  - the company's compliance with legal and regulatory requirements
  - the independent registered public accounting firm's qualifications and independence
  - the performance of our internal audit function and independent registered public accounting firm and
  - management of risk in the audit committee's areas of responsibility and
- arranges for the preparation of and approves the report that Securities and Exchange Commission rules require we include in our annual proxy statement.

Audit Committee Report

In connection with our financial statements for the year ended December 31, 2015, the audit committee has (1) reviewed and discussed the audited financial statements with management; (2) discussed with the independent registered public accounting firm (the "Auditors") the matters required to be discussed by Public Company Accounting Oversight Board Auditing Standard No. 16, Communications with Audit Committees; and (3) received the written disclosures and the letter from the Auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the Auditors' communications with the audit committee concerning independence, and has discussed with the Auditors their independence.

Based on the review and discussions referred to in items (1) through (3) of the above paragraph, the audit committee recommended to the board of directors that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2015, for filing with the Securities and Exchange Commission.

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

Compensation Committee

The compensation committee met six times during 2015. The compensation committee members are Thomas Everist, chair, Karen B. Fagg, William E. McCracken, and Patricia L. Moss.

The compensation committee's responsibilities, as set forth in its charter, include:

- review and recommend changes to the board regarding executive compensation policies for directors and executives
- evaluate the chief executive officer's performance and, either as a committee or together with other independent directors as directed by the board, determine his or her compensation
- recommend to the board the compensation of our other Section 16 officers and directors
- establish goals, make awards, review performance and determine, or recommend to the board, awards earned under our annual and long-term incentive compensation plans
- review and discuss with management the Compensation Discussion and Analysis and based upon such review and discussion, determine whether to recommend to the board that the Compensation Discussion and Analysis be included in our proxy statement and/or our Annual Report on Form 10-K
- arrange for the preparation of and approve the compensation committee report to be included in our proxy statement and/or Annual Report on Form 10-K
- assist the board in overseeing the management of risk in the committee's areas of responsibility and
- appoint, compensate, and oversee the work of any compensation consultant, legal counsel or other adviser retained by the compensation committee.

The compensation committee and the board of directors have sole and direct responsibility for determining compensation for our Section 16 officers and directors. The compensation committee makes recommendations to the board regarding compensation of all Section 16 officers, and the board then acts on the recommendations. The compensation committee and the board may not delegate their authority. They may, however, use recommendations from outside consultants, the chief executive officer, and the human resources department. The chief executive officer, the vice president-human resources, and general counsel regularly attend compensation committee meetings. The committee meets in executive session as needed. The committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on executive compensation. The competitive analysis is conducted internally in the other years. The committee did not retain a compensation consultant in 2015 to prepare a competitive assessment for 2016 compensation for our Section 16 officers.

The processes and procedures for consideration and determination of compensation of the Section 16 officers are discussed in the Compensation Discussion and Analysis. The role of our executive officers in determining or recommending compensation for our Section 16 officers is also discussed in the Compensation Discussion and Analysis.

During 2015, the vice president-human resources and the human resources department prepared the 2016 competitive assessment covering our Section 16 officers. The vice president-human resources and the human resources department also worked with the chief executive officer to:

- recommend salary grade midpoints, base salaries, annual and long-term incentive targets, benefit level increases under our Supplemental Income Security Plan, and employer contributions under our Nonqualified Defined Contribution Plan for our executive officers other than the chief executive officer and the vice president-human resources
- review recommended base salary grades, salary increases, and annual and long-term incentive targets submitted by executive officers for officers reporting to them for reasonableness and alignment with company or business segment objectives
- review and update annual and long-term incentive programs
- construct a recommended 2016 salary grade structure and
- verify the competitiveness of short-term and long-term incentive targets associated with salary grades, the industry competitiveness of the incentive awards threshold, target and maximum award levels and the degree of stretch in the goals, the mix of annual and long-term

compensation, and the use of total shareholder return as a single measure for long-term incentive and recommend modifications as appropriate.

Mr. Goodin recommended compensation for Patrick L. O'Bryan in connection with his promotion and Fidelity sales bonus incentive and for Steven L. Bietz in connection with his retirement. This is further discussed in the Compensation Discussion and Analysis contained herein.

The compensation committee has sole authority to retain or obtain the advice of compensation consultants, legal counsel or other advisers to assist in consideration of the compensation of the chief executive officer, the other Section 16 officers, and the board of directors. The committee is directly responsible for the appointment, compensation and oversight of the work of any adviser retained by the committee. Prior to retaining an adviser and annually, the committee will consider all factors relevant to the adviser's independence from management. The compensation committee charter requires the committee's pre-approval of the engagement of the committee's compensation consultants by the company for any other purpose. The compensation committee authorized the company to participate in compensation and employee benefits surveys sponsored by Towers Watson in 2015.

Annually the compensation committee conducts an assessment of any potential conflicts of interest raised by the work of any compensation consultant to determine if any conflict exists and how such conflict should be addressed. The compensation committee requested and received information from its compensation consultant, Towers Watson, to assist the committee in determining whether Towers Watson's work raised any conflict of interest. The compensation committee has reviewed Towers Watson's responses to its request and determined that the work of Towers Watson did not raise any conflict of interest in 2015.

The board of directors determines compensation for our non-employee directors based upon recommendations from the compensation committee. The compensation committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on director compensation.

In an engagement letter dated March 10, 2015, and signed by the chairman of the compensation committee, the compensation committee retained Towers Watson to prepare the 2015 compensation review for the board of directors. In its review of board of director compensation, Towers Watson was asked to:

- identify market trends relative to director compensation
- report on the competitive position of our director compensation program as compared to our performance graph peer group
- recommend alternatives for our board of directors to consider and
- review the performance graph peer group companies to identify practices relating to director recruitment.

At its May 2015 meeting, the committee reviewed the report by Towers Watson on director compensation competitiveness, considering both level and design. The Towers Watson report focused on broad-based Fortune 500 market trends and the then current peer group consisting of 23 companies. The report noted that for Fortune 500 companies, median total director compensation increased nine percent over the last two years. The report noted that the median total director compensation of the 23 peer group companies is $178,800 compared to the company's typical director total compensation of $175,000. The company's cash compensation approximates the 25th percentile, whereas the equity compensation is just above the median. Nonexecutive chairman of the board fees for the peer group range between $80,000 and $135,000. The company pays additional compensation of $90,000 for this position. The report indicated additional compensation for committee chairs is generally between $5,000 and $15,000 which varies by committee. The company's additional retainers for committee chairs are $10,000 for the Compensation Committee and Nominating and Governance Committee, and $15,000 for the Audit Committee which aligned with market practices. The company's vice president-human resources provided additional information at the meeting from the National Association of Corporate Directors 2014-2015 Director Compensation Report. The report noted that for 2014 the median direct compensation for all large companies (having revenues of $2.5 billion to $10 billion) was $214,283, for all size utilities was $165,907, for all size energy companies was $244,167, and for all size material companies was $170,249. After considering the reports, the compensation committee recommended, and the board of directors approved, no change to the current annual cash base retainer of $65,000, $110,000 equity grant, committee chair retainers, and additional retainer for the nonexecutive chairman of the board.

Stockholder Communications

Stockholders and other interested parties who wish to contact the board of directors or an individual director, including our non-employee chairman or non-employee directors as a group, should address a communication in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. The secretary will forward all communications.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16 of the Securities Exchange Act of 1934, as amended, requires that officers, directors, and holders of more than 10% of our common stock file reports of their trading in our equity securities with the Securities and Exchange Commission. Based solely on a review of Forms 3, 4, and 5 and any amendments to these forms furnished to us during and with respect to 2015 or written representations that no Forms 5 were required, we believe that all such reports were timely filed.

CONDUCT OF MEETING; ADJOURNMENT

The chairman of the board has broad responsibility and authority to conduct the annual meeting in an orderly and timely manner. In addition, our bylaws provide that the meeting may be adjourned from time to time by the chairman of the meeting regardless of whether a quorum is present.

OTHER BUSINESS

Neither the board of directors nor management intends to bring before the meeting any business other than the matters referred to in the notice of annual meeting and this proxy statement. We have not been informed that any other matter will be presented at the meeting by others. However, if any other matters are properly brought before the annual meeting, or any adjournment(s) thereof, your proxies include discretionary authority for the persons named in the enclosed proxy to vote or act on such matters in their discretion.

SHARED ADDRESS STOCKHOLDERS

In accordance with a notice sent to eligible stockholders who share a single address, we are sending only one annual report to stockholders and one proxy statement to that address unless we received instructions to the contrary from any stockholder at that address. This practice, known as “householding,” is designed to reduce our printing and postage costs. However, if a stockholder of record wishes to receive a separate annual report to stockholders and proxy statement in the future, he or she may contact the office of the treasurer at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. Eligible stockholders of record who receive multiple copies of our annual report to stockholders and proxy statement can request householding by contacting us in the same manner. Stockholders who own shares through a bank, broker, or other nominee can request householding by contacting the nominee.

We hereby undertake to deliver promptly, upon written or oral request, a separate copy of the annual report to stockholders and proxy statement to a stockholder at a shared address to which a single copy of the document was delivered.

2017 ANNUAL MEETING OF STOCKHOLDERS

Director Nominations: Our bylaws provide that director nominations may be made only (i) at any meeting of stockholders, by or at the direction of the board or (ii) at an annual meeting of stockholders, by a stockholder of record, as provided in the bylaws, who is entitled to vote upon the election of directors and who has complied with the procedures established by the bylaws. For a nomination to be properly brought before an annual meeting by a stockholder, the stockholder intending to make the nomination must have given timely and proper notice of the nomination in writing to the corporate secretary in accordance with and containing all information, including the completed questionnaire, provided for in the bylaws. To be timely, such notice must be delivered or mailed to the corporate secretary and received at our principal executive offices not later than the close of business on the 90th day prior to the first anniversary of the preceding year’s annual meeting of stockholders. For purposes of our annual meeting of stockholders expected to be held April 25, 2017, any stockholder who wishes to submit a nomination must submit the required notice to the corporate secretary not later than the close of business on January 26, 2017.

Other Meeting Business: Our bylaws also provide that business, other than director nominations, may be properly brought before (i) any meeting of stockholders, by or at the direction of the board or (ii) an annual meeting of stockholders, by a stockholder of record, as provided in the bylaws, who is entitled to vote upon the election of directors and the proposal and who has complied with the procedures established by the bylaws. For business to be properly brought before an annual meeting by a stockholder (other than director nominations which are described above), the stockholder must have given timely and proper notice of such business in writing to the corporate secretary, in accordance with and containing all information provided for in the bylaws and such business must be a proper matter for stockholder action under the General Corporation Law of Delaware. To be timely, such notice must be delivered or mailed to the corporate secretary and received at our principal executive offices not later than the close of business on the 90th day prior to the first anniversary of the preceding year’s annual meeting of stockholders. For purposes of our annual meeting of stockholders expected to be held April 25, 2017, any stockholder who wishes to bring business before the meeting (other than director nominations which are described above) must submit the required notice to the corporate secretary not later than the close of business on January 26, 2017.

Discretionary Voting: Rule 14a-4 of the Securities and Exchange Commission's proxy rules allows us to use discretionary voting authority to vote on matters coming before an annual stockholders' meeting if we do not have notice of the matter at least 45 days before the anniversary date on which we first mailed our proxy materials for the prior year's annual stockholders' meeting or the date specified by an advance notice provision in our bylaws. Our bylaws contain an advance notice provision that we have described above. For our annual meeting of stockholders expected to be held on April 25, 2017, stockholders must submit such written notice to the corporate secretary not later than the close of business on January 26, 2017.

Stockholder Proposals: The requirements we describe above are separate from and in addition to the Securities and Exchange Commission's requirements that a stockholder must meet to have a stockholder proposal included in our proxy statement pursuant to Rule 14a-8 under the Exchange Act. For purposes of our annual meeting of stockholders expected to be held on April 25, 2017, any stockholder who wishes to submit a proposal for inclusion in our proxy materials must submit such proposal to the corporate secretary on or before November 16, 2016.

Bylaw Copies: You may obtain a copy of the full text of the bylaw provisions discussed above by writing to the corporate secretary. Our bylaws are also available on our website at: http://www.mdu.com/integrity/governance/guidelines-and-bylaws.

We will make available to our stockholders to whom we furnish this proxy statement a copy of our Annual Report on Form 10-K, excluding exhibits, for the year ended December 31, 2015, which is required to be filed with the Securities and Exchange Commission. You may obtain a copy, without charge, upon written or oral request to the Office of the Treasurer of MDU Resources Group, Inc., 1200 West Century Avenue, Mailing Address: P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. You may also access our Annual Report on Form 10-K through our website at www.mdu.com.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary
March 16, 2016

EXHIBIT A

MDU RESOURCES GROUP, INC. LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

Article 1. Establishment, Purpose and Duration

1.1 *Establishment of the Plan.* MDU Resources Group, Inc., a Delaware corporation (hereinafter referred to as the "Company"), hereby establishes an incentive compensation plan to be known as the "MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan" (hereinafter referred to as the "Plan"), as set forth in this document. The Plan permits the grant of Restricted Stock, Performance Units, Performance Shares and other awards.

The Plan first became effective when approved by the stockholders at the annual meeting on April 22, 1997. The Plan, as amended, became effective on April 25, 2006 when approved by the stockholders at the 2006 annual meeting. The Plan shall remain in effect as provided in Section 1.3 herein.

1.2 *Purpose of the Plan.* The purpose of the Plan is to promote the success and enhance the value of the Company by linking the personal interests of Participants to those of Company stockholders and customers.

The Plan is further intended to provide flexibility to the Company in its ability to motivate, attract and retain the services of Participants upon whose judgment, interest and special effort the successful conduct of its operations is largely dependent.

1.3 *Duration of the Plan.* The Plan shall remain in effect, subject to the right of the Board of Directors to terminate the Plan at any time pursuant to Article 13 herein, until all Shares subject to it shall have been purchased or acquired according to the Plan's provisions.

Article 2. Definitions

Whenever used in the Plan, the following terms shall have the meanings set forth below and, when such meaning is intended, the initial letter of the word is capitalized:

2.1 *"Award"* means, individually or collectively, a grant under the Plan of Restricted Stock, Performance Units, Performance Shares or any other type of award permitted under Article 8 of the Plan.

2.2 *"Award Agreement"* means an agreement entered into by each Participant and the Company, setting forth the terms and provisions applicable to an Award granted to a Participant under the Plan.

2.3 *"Board"* or *"Board of Directors"* means the Board of Directors of the Company.

2.4 A *"Change in Control"* shall mean:

(a) The acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (i) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change in Control: (i) any acquisition directly from the Company, (ii) any acquisition by the Company, (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company or (iv) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this Section 2.4; or

(b) Individuals who, as of April 22, 1997, which is the effective date of the Plan, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

For avoidance of doubt, unless otherwise determined by the Board, the sale of a subsidiary, operating entity or business unit of the Company shall not constitute a Change in Control for purposes of this Agreement.

2.5 *"Code"* means the Internal Revenue Code of 1986, as amended from time to time.

2.6 *"Committee"* means the Committee, as specified in Article 3, appointed by the Board to administer the Plan with respect to Awards.

2.7 *"Company"* means MDU Resources Group, Inc., a Delaware corporation, or any successor thereto as provided in Article 16 herein.

2.8 *"Covered Employee"* means any Participant who would be considered a "Covered Employee" for purposes of Section 162(m) of the Code.

2.9 *"Director"* means any individual who is a member of the Board of Directors of the Company.

2.10 *"Disability"* means "permanent and total disability" as defined under Section 22(e)(3)of the Code.

2.11 *"Dividend Equivalent"* means, with respect to Shares subject to an Award, a right to be paid an amount equal to dividends declared on an equal number of outstanding Shares.

2.12 *"Eligible Employee"* means an Employee who is eligible to participate in the Plan, as set forth in Section 5.1 herein.

2.13 *"Employee"* means any full-time or regularly-scheduled part-time employee of the Company or of the Company's Subsidiaries, who is not covered by any collective bargaining agreement to which the Company or any of its Subsidiaries is a party. Directors who are not otherwise employed by the Company shall not be considered Employees for purposes of the Plan. For purposes of the Plan, transfer of employment of a Participant between the Company and any one of its Subsidiaries (or between Subsidiaries) shall not be deemed a termination of employment.

2.14 *"Exchange Act"* means the Securities Exchange Act of 1934, as amended from time to time, or any successor act thereto.

2.15 *"Fair Market Value"* shall mean the average of the high and low sale prices as reported in the consolidated transaction reporting system or, if there is no such sale on the relevant date, then on the last previous day on which a sale was reported.

2.16 *"Full Value Award"* means an Award pursuant to which Shares may be issued.

2.17 *"Participant"* means an Employee of the Company who has outstanding an Award granted under the Plan.

2.18 *"Performance Goals"* means the performance goals established by the Committee, which shall be based on one or more of the following measures: sales or revenues, earnings per share, shareholder return and/or value, funds from operations, cash flow from operations (dollar target or as % of revenue), gross margin or gross profit (dollar target or as % of revenue), operations and maintenance expense (dollar target or as % of revenue), general and administrative expense (dollar target or as % of revenue), total operating expense (dollar target or as % of revenue), operating income (dollar target or as % of revenue), pretax income (dollar target or as % of revenue), earnings before interest, taxes, depreciation and amortization or "EBITDA" (dollar target or as % of revenue), earnings before interest and taxes or "EBIT" (dollar target or as % of revenue), gross income, net income, cash flow, earnings, return on equity, return on invested capital, return on assets, return on net assets, working capital as percentage of revenue, days sales outstanding/accounts receivable turnover, current ratio, capital efficiency, operating ratios, stock price, enterprise value, company value, asset value growth, net asset value, shareholders' equity, dividends, customer satisfaction, accomplishment of mergers, acquisitions, dispositions or similar extraordinary business transactions, safety, sustainability, profit returns and margins, financial return ratios, and market performance. Performance goals may be measured solely on a corporate, subsidiary, business unit or individual basis, or a combination thereof. Performance goals may reflect absolute entity or individual performance or a relative comparison of entity or individual performance to the performance of a peer group of entities or other external measure.

2.19 *"Performance Unit"* means an Award granted to an Employee, as described in Article 7 herein.

2.20 *"Performance Share"* means an Award granted to an Employee, as described in Article 7 herein.

2.21 *"Period of Restriction"* means the period during which the transfer of Restricted Stock is limited in some way, as provided in Article 6 herein.

2.22 *"Person"* shall have the meaning ascribed to such term in Section 3(a)(9) of the Exchange Act, as used in Sections 13(d) and 14 (d) thereof, including usage in the definition of a "group" in Section 13(d) thereof.

2.23 *"Qualified Restricted Stock"* means an Award of Restricted Stock designated as Qualified Restricted Stock by the Committee at the time of grant and intended to qualify for the exemption from the limitation on deductibility imposed by Section 162(m) of the Code that is set forth in Section 162(m)(4)(C).

2.24 *"Restricted Stock"* means an Award of Shares granted to a Participant pursuant to Article 6 herein.

2.25 *"Shares"* means the shares of common stock of the Company.

2.26 *"Subsidiary"* means any corporation that is a "subsidiary corporation" of the Company as that term is defined in Section 424(f) of the Code.

Article 3. Administration

3.1 *The Committee.* The Plan shall be administered by the Compensation Committee of the Board, or by any other Committee appointed by the Board. The members of the Committee shall be appointed from time to time by, and shall serve at the discretion of, the Board of Directors.

3.2 *Authority of the Committee.* The Committee shall have full power except as limited by law, the Articles of Incorporation and the Bylaws of the Company, subject to such other restricting limitations or directions as may be imposed by the Board and subject to the provisions herein, to determine the size and types of Awards; to determine the terms and conditions of such Awards in a manner consistent with the Plan; to construe and interpret the Plan and any agreement or instrument entered into under the Plan; to establish, amend or waive rules and regulations for the Plan's administration; and (subject to the provisions of Article 13 herein) to amend the terms and conditions of any outstanding Award. Further, the Committee shall make all other determinations which may be necessary or advisable for the administration of the Plan. As permitted by law, the Committee may delegate its authorities as identified hereunder.

3.3 *Restrictions on Share Transferability.* The Committee may impose such restrictions on any Shares acquired pursuant to Awards under the Plan as it may deem advisable, including, without limitation, restrictions to comply with applicable Federal securities laws, with the requirements of any stock exchange or market upon which such Shares are then listed and/or traded and with any blue sky or state securities laws applicable to such Shares.

3.4 *Approval.* The Board or the Committee shall approve all Awards made under the Plan and all elections made by Participants, prior to their effective date, to the extent necessary to comply with Rule 16b-3 under the Exchange Act.

3.5 *Decisions Binding.* All determinations and decisions made by the Committee pursuant to the provisions of the Plan and all related orders or resolutions of the Board shall be final, conclusive and binding on all persons, including the Company, its stockholders, Employees, Participants and their estates and beneficiaries.

3.6 *Costs.* The Company shall pay all costs of administration of the Plan.

Article 4. Shares Subject to the Plan

4.1 *Number of Shares.* Subject to Section 4.2 herein, the maximum number of Shares that may be issued pursuant to Awards under the Plan shall be 9,242,806. Shares underlying lapsed or forfeited Awards of Restricted Stock shall not be treated as having been issued pursuant to an Award under the Plan. Shares withheld from an Award to satisfy tax withholding obligations shall be counted as Shares issued pursuant to an Award under the Plan. Shares that are potentially deliverable under an Award that expires or is canceled, forfeited, settled in cash or otherwise settled without the delivery of Shares shall not be treated as having been issued under the Plan.

Shares issued pursuant to the Plan may be (i) authorized but unissued Shares of Common Stock, (ii) treasury shares, or (iii) shares purchased on the open market.

4.2 *Adjustments in Authorized Shares.* In the event of any equity restructuring such as a stock dividend, stock split, spinoff, rights offering or recapitalization through a large, nonrecurring cash dividend, the Committee shall cause an equitable adjustment to be made (i) in the number and kind of Shares that may be delivered under the Plan, (ii) in the individual limitations set forth in Section 4.3 and (iii) with respect to outstanding Awards, in the number and kind of Shares subject to outstanding Awards, price of Shares subject to outstanding Awards, any Performance Goals relating to Shares, the market price of Shares, or per-Share results, and other terms and conditions of outstanding Awards, in the case of (i), (ii) and (iii) to prevent dilution or enlargement of rights. In the event of any other change in corporate capitalization, such as a merger, consolidation or liquidation, the Committee may, in its sole discretion, cause an equitable adjustment as described in the foregoing sentence to be made to prevent dilution or enlargement of rights. The number of Shares subject to any Award shall always be rounded down to a whole number when adjustments are made pursuant to this Section 4.2. Adjustments made by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

4.3 *Individual Limitations.* Subject to Section 4.2 herein, (i) the total number of shares of Qualified Restricted Stock that may be granted in any calendar year to any Covered Employee shall not exceed 2,250,000 Shares; (ii) the total number of Performance Shares or Performance Units that may be granted in any calendar year to any Covered Employee shall not exceed 2,250,000 Performance Shares or Performance Units, as the case may be; (iii) the total number of Shares that are intended to qualify for deduction under Section 162(m) of the Code granted pursuant to Article 8 herein in any calendar year to any Covered Employee shall not exceed 2,250,000 Shares; (iv) the total cash Award that is intended to qualify for deduction under Section 162(m) of the Code that may be paid pursuant to Article 8 herein in any calendar year to any Covered Employee shall not exceed $6,000,000; and (v) the aggregate number of Dividend Equivalents that are intended to qualify for deduction under Section 162 (m) of the Code that a Covered Employee may receive in any calendar year shall not exceed $6,000,000.

Article 5. Eligibility and Participation

5.1 *Eligibility.* Persons eligible to participate in the Plan include all officers and key employees of the Company and its Subsidiaries, as determined by the Committee, including Employees who are members of the Board, but excluding Directors who are not Employees.

5.2 *Actual Participation.* Subject to the provisions of the Plan, the Committee may, from time to time, select from all eligible Employees those to whom Awards shall be granted and shall determine the nature and amount of each Award.

Article 6. Restricted Stock

6.1 *Grant of Restricted Stock.* Subject to the terms and conditions of the Plan, Restricted Stock may be granted to Eligible Employees at any time and from time to time, as shall be determined by the Committee.

The Committee shall have complete discretion in determining the number of shares of Restricted Stock granted to each Participant (subject to Article 4 herein) and, consistent with the provisions of the Plan, in determining the terms and conditions pertaining to such Restricted Stock.

In addition, the Committee may, prior to or at the time of grant, designate an Award of Restricted Stock as Qualified Restricted Stock, in which event it will condition the grant or vesting, as applicable, of such Qualified Restricted Stock upon the attainment of the Performance Goals selected by the Committee.

6.2 *Restricted Stock Award Agreement.* Each Restricted Stock grant shall be evidenced by a Restricted Stock Award Agreement that shall specify the Period or Periods of Restriction, the number of Restricted Stock Shares granted and such other provisions as the Committee shall determine.

6.3 *Transferability.* Restricted Stock granted hereunder may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated until the end of the applicable Period of Restriction established by the Committee and specified in the Restricted Stock Award Agreement. All rights with respect to the Restricted Stock granted to a Participant under the Plan shall be available during his or her lifetime only to such Participant or his or her legal representative.

6.4 *Certificate Legend.* Each certificate representing Restricted Stock granted pursuant to the Plan may bear a legend substantially as follows:

"The sale or other transfer of the shares of stock represented by this certificate, whether voluntary, involuntary or by operation of law, is subject to certain restrictions on transfer as set forth in MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan and in a Restricted Stock Award Agreement. A copy of such Plan and such Agreement may be obtained from MDU Resources Group, Inc."

The Company shall have the right to retain the certificates representing Restricted Stock in the Company's possession until such time as all restrictions applicable to such Shares have been satisfied.

6.5 *Removal of Restrictions.* Restricted Stock shall become freely transferable by the Participant after the last day of the Period of Restriction applicable thereto. Once Restricted Stock is released from the restrictions, the Participant shall be entitled to have the legend referred to in Section 6.4 removed from his or her stock certificate.

6.6 *Voting Rights.* During the Period of Restriction, Participants holding Restricted Stock may exercise full voting rights with respect to those Shares.

6.7 *Dividends and Other Distributions.* Subject to the Committee's right to determine otherwise at the time of grant, during the Period of Restriction, Participants holding Restricted Stock shall receive all regular cash dividends paid with respect to all Shares while they are so held. All other distributions paid with respect to such Restricted Stock shall be credited to Participants subject to the same restrictions on transferability and forfeitability as the Restricted Stock with respect to which they were paid and shall be paid to the Participant within forty-five (45) days following the full vesting of the Restricted Stock with respect to which such distributions were made.

6.8 *Termination of Employment.* Each Restricted Stock Award Agreement shall set forth the extent to which the Participant shall have the right to receive unvested Restricted Stock following termination of the Participant's employment with the Company and its Subsidiaries. Such provisions shall be determined in the sole discretion of the Committee, shall be included in the Restricted Stock Award Agreement entered into with Participants, need not be uniform among all grants of Restricted Stock or among Participants and may reflect distinctions based on the reasons for termination of employment.

Article 7. Performance Units and Performance Shares

7.1 *Grant of Performance Units and Performance Shares.* Subject to the terms and conditions of the Plan, Performance Units and/or Performance Shares may be granted to an Eligible Employee at any time and from time to time, as shall be determined by the Committee.

The Committee shall have complete discretion in determining the number of Performance Units and/or Performance Shares granted to each Participant (subject to Article 4 herein) and, consistent with the provisions of the Plan, in determining the terms and conditions pertaining to such Awards.

7.2 *Performance Unit/Performance Share Award Agreement.* Each grant of Performance Units and/or Performance Shares shall be evidenced by a Performance Unit and/or Performance Share Award Agreement that shall specify the number of Performance Units and/or Performance Shares granted, the initial value (if applicable), the Performance Period, the Performance Goals and such other provisions as the Committee shall determine, including but not limited to any rights to Dividend Equivalents.

7.3 *Value of Performance Units/Performance Shares.* Each Performance Unit shall have an initial value that is established by the Committee at the time of grant. The value of a Performance Share shall be equal to the Fair Market Value of a Share. The Committee shall set Performance Goals in its discretion which, depending on the extent to which they are met, will determine the number and/or value of Performance Units/Performance Shares that will be paid out to the Participants. The time period during which the Performance Goals must be met shall be called a "Performance Period."

7.4 *Earning of Performance Units/Performance Shares.* After the applicable Performance Period has ended, the holder of Performance Units/Performance Shares shall be entitled to receive a payout with respect to the Performance Units/Performance Shares earned by the Participant over the Performance Period, to be determined as a function of the extent to which the corresponding Performance Goals have been achieved.

7.5 *Form and Timing of Payment of Performance Units/Performance Shares.* Payment of earned Performance Units/Performance Shares shall be made following the close of the applicable Performance Period. The Committee, in its sole discretion, may pay earned Performance Units/Performance Shares in cash or in Shares (or in a combination thereof), which have an aggregate Fair Market Value equal to the value of the earned Performance Units/Performance Shares at the close of the applicable Performance Period. Such Shares may be granted subject to any restrictions deemed appropriate by the Committee.

7.6 *Termination of Employment.* Each Performance Unit/Performance Share Award Agreement shall set forth the extent to which the Participant shall have the right to receive a Performance Unit/Performance Share payment following termination of the Participant's employment with the Company and its Subsidiaries during a Performance Period. Such provisions shall be determined in the sole discretion of the Committee, shall be included in the Award Agreement entered into with Participants, need not be uniform among all grants of Performance Units/Performance Shares or among Participants and may reflect distinctions based on reasons for termination of employment.

7.7 *Transferability.* Except as otherwise determined by the Committee and set forth in the Performance Unit/Performance Share Award Agreement, Performance Units/Performance Shares may not be sold, transferred, pledged, assigned or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution, and a Participant's rights with respect to Performance Units/Performance Shares granted under the Plan shall be available during the Participant's lifetime only to such Participant or the Participant's legal representative.

Article 8. Other Awards

The Committee shall have the right to grant other Awards which may include, without limitation, the grant of Shares based on attainment of Performance Goals established by the Committee, the payment of Shares in lieu of cash, the payment of cash based on attainment of Performance Goals established by the Committee, and the payment of Shares in lieu of cash under other Company incentive or bonus programs. Payment under or settlement of any such Awards shall be made in such manner and at such times as the Committee may determine.

Article 9. Beneficiary Designation

Each Participant under the Plan may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under the Plan is to be paid in case of his or her death before he or she receives any or all of such benefit. Each such designation shall revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. In the absence of any such designation, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

The spouse of a married Participant domiciled in a community property jurisdiction shall join in any designation of beneficiary or beneficiaries other than the spouse.

Article 10. Deferrals

The Committee may permit a Participant to defer the Participant's receipt of the payment of cash or the delivery of Shares that would otherwise be due to such Participant under the Plan. If any such deferral election is permitted, the Committee shall, in its sole discretion, establish rules and procedures for such payment deferrals.

Article 11. Rights of Employees

11.1 *Employment.* Nothing in the Plan shall interfere with or limit in any way the right of the Company to terminate any Participant's employment at any time, for any reason or no reason in the Company's sole discretion, nor confer upon any Participant any right to continue in the employ of the Company.

11.2 *Participation.* No Employee shall have the right to be selected to receive an Award under the Plan, or, having been so selected, to be selected to receive a future Award.

Article 12. Change in Control

The terms of this Article 12 shall immediately become operative, without further action or consent by any person or entity, upon a Change in Control, and once operative shall supersede and take control over any other provisions of this Plan.

Upon a Change in Control

(a) Any restriction periods and restrictions imposed on Restricted Stock, Qualified Restricted Stock or Awards granted pursuant to Article 8 (if not performance-based) shall be deemed to have expired and such Restricted Stock, Qualified Restricted Stock or Awards shall become immediately vested in full; and

(b) The target payout opportunity attainable under all outstanding Awards of Performance Units, Performance Shares and Awards granted pursuant to Article 8 (if performance-based) shall be deemed to have been fully earned for the entire Performance Period(s) as of the effective date of the Change in Control, and shall be paid out promptly in Shares or cash pursuant to the terms of the Award Agreement, or in the absence of such designation, as the Committee shall determine.

Article 13. Amendment, Modification and Termination

13.1 *Amendment, Modification and Termination.* The Board may, at any time and from time to time, alter, amend, suspend or terminate the Plan, in whole or in part, provided that no amendment shall be made which shall increase the total number of Shares that may be issued under the Plan, materially modify the requirements for participation in the Plan, or materially increase the benefits accruing to Participants under the Plan, in each case unless such amendment is approved by the stockholders.

13.2 *Awards Previously Granted.* No termination, amendment or modification of the Plan shall adversely affect in any material way any Award previously granted under the Plan, without the written consent of the Participant holding such Award, unless such termination, modification or amendment is required by applicable law and except as otherwise provided herein.

Article 14. Withholding

14.1 *Tax Withholding.* The Company shall have the power and the right to deduct or withhold, or require a Participant to remit to the Company, an amount sufficient to satisfy Federal, state and local taxes (including the Participant's FICA obligation) required by law to be withheld with respect to an Award made under the Plan.

14.2 *Share Withholding.* With respect to withholding required upon the lapse of restrictions on Restricted Stock, or upon any other taxable event arising out of or as a result of Awards granted hereunder, Participants may elect to satisfy the withholding requirement, in whole or in part, by tendering previously-owned Shares or by having the Company withhold Shares having a Fair Market Value on the date the tax is to be determined equal to the statutory total tax which could be imposed on the transaction. All elections shall be irrevocable, made in writing and signed by the Participant.

Article 15. Minimum Vesting

Notwithstanding any other provision of the Plan to the contrary, (a) the minimum vesting period for Full Value Awards with no performance-based vesting characteristics must be at least three years (vesting may occur ratably each month, quarter or anniversary of the grant date over such vesting period); (b) the minimum vesting period for Full Value Awards with performance-based vesting characteristics must be at least one year; and (c) the Committee shall not have discretion to accelerate vesting of Full Value Awards except in the event of a Change in Control or similar transaction, or the death, disability, or termination of employment of a Participant; provided, however, that the Committee may grant a "de minimis" number of Full Value Awards that do not comply with the foregoing minimum vesting standards. For this purpose "de minimis" means 331,279 Shares available for issuance as Full Value Awards under the Plan, subject to adjustment under Section 4.2 herein.

Article 16. Successors

All obligations of the Company under the Plan, with respect to Awards granted hereunder, shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation or otherwise, of all or substantially all of the business and/or assets of the Company.

Article 17. Legal Construction

17.1 *Gender and Number.* Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine, the plural shall include the singular and the singular shall include the plural.

17.2 *Severability.* In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

17.3 *Requirements of Law.* The granting of Awards and the issuance of Shares under the Plan shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

17.4 *Governing Law.* To the extent not preempted by Federal law, the Plan, and all agreements hereunder, shall be construed in accordance with, and governed by, the laws of the State of Delaware.

Article 18. Accounting Restatements

This Article 18 shall apply to Awards granted to all Participants in the Plan. Notwithstanding anything in the Plan or in any Award Agreement to the contrary, if the Company is required to prepare an accounting restatement due to material noncompliance with any financial reporting requirements under the securities laws, the Company or the Committee may, or shall if required, take action to recover incentive-based compensation from specific executive officers in accordance with the Company's *Guidelines for Repayment of Incentives Due to Accounting Restatements*, as they may be amended or substituted from time to time, and in accordance with applicable law and applicable rules of the Securities and Exchange Commission and the New York Stock Exchange.

Article 19. Code Section 409A Compliance

To the extent applicable, it is intended that this Plan and any Awards granted hereunder comply with the requirements of Section 409A of the Code and any related regulations or other guidance promulgated with respect to such Section by the U.S. Department of the Treasury or the Internal Revenue Service ("Section 409A"). Any provision that would cause the Plan or any Award granted hereunder to fail to satisfy Section 409A shall have no force or effect until amended to comply with Section 409A, which amendment may be retroactive to the extent permitted by Section 409A.

EXHIBIT B

Towers Watson 2013 CDB General Industry Executive Database

3M
A.O. Smith
AbbVie
Accenture
ACH Food
Adecco
Aerojet
AGCO
Agilent Technologies
Agrium
Aimia
Air Liquide
Air Products and Chemicals
Alcoa
Alexander & Baldwin
Alliant Techsystems
American Crystal Sugar
American Sugar Refining
Americas Styrenics
AmerisourceBergen
AMETEK
Amgen
AMR
AMSTED Industries
Amway
Ansell
AptarGroup
ARAMARK
Arby's Restaurant Group
Archer Daniels Midland
Arkema
Armstrong World Industries
Arrow Electronics
Ashland
AstraZeneca
AT&T
Automatic Data Processing
Avaya
Avery Dennison
Avis Budget Group
Avon Products
Axiall Corporation
BAE Systems
Ball
Barnes Group
Barrick Gold of North America
Baxter International
Bayer
Bayer Business & Technology Services
Bayer CropScience
Bayer HealthCare
BD (Becton Dickinson)
Beam
Bechtel Systems & Infrastructure
Benjamin Moore
Best Buy
Big Lots
Biogen Idec
Black Box
Boise
Boise Cascade
Booz Allen Hamilton
BorgWarner
Boston Scientific
Brady
Bristol-Myers Squibb
Bunge
Burlington Northern Santa Fe
Bush Brothers
CA Technologies
Caesar's Entertainment
Calgon Carbon
Cardinal Health
Cargill
Carlson
CarMax
Carmeuse North America Group
Carnival
Carpenter Technology
Carriage Services
Catalent Pharma Solutions
CBS
Celestica
Celgene
CEVA Logistics
CF Industries
CH2M Hill
Chemtura
Christensen Farms
Chrysler
CHS
Cisco Systems
Clear Channel Communications
Cliffs Natural Resources
Cloud Peak Energy
CNH
Coach
Coca-Cola
Coinstar
Colgate-Palmolive
Columbia Sportswear
Comcast
Commercial Metals
Compass Group
ConAgra Foods
Convergys
Cooper Standard Automotive
Corning
Cott Corporation
Covance
Covidien
CSX
Cumberland Gulf Group
Curtiss-Wright
CVS Caremark
Cytec
Daiichi Sankyo
Daimler Trucks North America
Darden Restaurants
Day & Zimmermann
Dean Foods
Deere & Company
Dell
Deluxe
Dentsply
Diageo North America
Donaldson Company
Dow Corning
Dr Pepper Snapple
DSM Nutritional Products
DuPont
E.W. Scripps
Eastman Chemical
Eaton
eBay
Ecolab
Eli Lilly
EMC
EMD Millipore
Emerson Electric
EnCana Oil & Gas USA
Engility Corporation
EnPro Industries
Equifax
Equity Office Properties
Ericsson
ESRI
Estee Lauder
Esterline Technologies
Exel
Exelis
Expedia
Experian Americas
Express Scripts
Exterran
Federal-Mogul
First Data
Fiserv
Flowserve
Ford
Fortune Brands Home & Security
Freeport-McMoRan Copper & Gold
Frontier Communications
Fujitsu Limited
G&K Services
GAF Materials
Gap
Gartner
Gates
Gavilon
GenCorp
General Atomics
General Dynamics
General Mills
General Motors
Gerdau Long Steel North America
Gilead Sciences
GlaxoSmithKline
Goodman Manufacturing
Goodyear Tire & Rubber
Google
Graco
Green Mountain Coffee Roasters
Grupo Ferrovial
GTECH
H.B. Fuller
Hanesbrands
Harland Clarke
Harman International Industries
Harsco
Hasbro
HBO
HD Supply
Henry Schein
Herman Miller
Hershey
Hertz
Hexcel
Hilton Worldwide
Hitachi Data Systems
HNI
HNTB
Hoffmann-La Roche
Home Depot
Hormel Foods
Host Hotels & Resorts
Houghton Mifflin Harcourt Publishing
Hunt Consolidated
Husky Injection Molding Systems
IBM
IDEXX Laboratories
Illinois Tool Works
Ingersoll Rand
Intel
Intercontinental Hotels Group
International Automotive Components

International Flavors & Fragrances
International Game Technology
International Paper
Invensys Controls
ION Geophysical
Irvine
ITT Corporation
J.M. Smucker
J.R. Simplot
Jabil Circuit
Jacobs Engineering
JetBlue Airways
Johns-Manville
Johnson & Johnson
Johnson Controls
KBR
Kellogg
Kelly Services
Kennametal
Kewaunee Scientific Corporation
Keystone Foods
Kimberly-Clark
Kimco Realty
Kinross Gold
Koch Industries
Kofax
Kohler
Kyocera Corporation
L-3 Communications
Land O'Lakes
Leggett and Platt
Lehigh Hanson
Lend Lease
Leprino Foods
Level 3 Communications
Life Technologies
Lifetouch
Lincoln Electric
Lorillard Tobacco
LyondellBasell
Magellan Midstream Partners
Makino
Manitowoc
Marriott International
Martin Marietta Materials
Mary Kay
Masco
Mattel
Matthews International
McDermott International
McDonald's
McKesson
MeadWestvaco
Media General
Medtronic
Menasha Corporation
Merck & Co
Micron Technology
Microsoft
Milacron
MillerCoors
Millicom International Cellular
Mine Safety Appliances
Molnlycke Health Care
Molson Coors Brewing
Molycorp
Momentive Specialty Chemicals
Mosaic
MTS Systems
Nash-Finch
Navigant Consulting
Navistar International
NBTY
NCR
Neoris USA
Nestle USA
Newell Rubbermaid
Newmont Mining
NewPage
Nissan North America
Nokia
Norfolk Southern
NOVA Chemicals
Novartis
Novo Nordisk Pharmaceuticals
Nypro
Occidental Petroleum
Office Depot
Omgeo
Omnicare
OMNOVA Solutions
Orange Business Services
Oshkosh
Owens Corning
Owens-Illinois
Oxford Instruments America
Pall Corporation
Panasonic of North America
Parker Hannifin
Parsons Corporation
PepsiCo
Performance Food Group
Pfizer
PGI (Polymer Group)
PHH
PHI
Pitney Bowes
Plexus
Plum Creek Timber
Polaris Industries
PolyOne
Potash
PPG Industries
Praxair
PulteGroup
Purdue Pharma
Qualcomm
Quest Diagnostics
Quintiles
R.R. Donnelley
Rayonier
Regal-Beloit
Regeneron Pharmaceuticals
Revlon
Reynolds Packaging
Ricoh Americas
Roche Diagnostics
Rockwell Automation
Rockwell Collins
Rolls-Royce North America
Rowan Companies
Ryder System
S.C. Johnson & Son
Sage Software
SAIC
Sanofi
SAS Institute
Schreiber Foods
Schwan's
Scotts Miracle-Gro
Seagate Technology
Sealed Air
Serco
ServiceMaster Company
ShawCor
Sherwin-Williams
Shire
Sigma-Aldrich
Snap-on
Sodexo
Sonoco Products
Sony Electronics
Southwest Airlines
Spirit AeroSystems
Sprint Nextel
SPX
SSAB
St. Jude Medical
Staples
Starbucks Coffee
Starwood Hotels & Resorts
Statoil
Steelcase
Stryker
Suburban Propane
Syngenta Crop Protection
Target
Taubman Centers
TE Connectivity
TeleTech Holdings
Teradata
Terex
Tetra Tech
Texas Instruments
Textron
Thermo Fisher Scientific
Thomson Reuters
Tiffany & Co.
Time Warner
Time Warner Cable
T-Mobile
Toro
Toshiba Medical Research Institute USA
Total System Service (TSYS)
Toyota Motor Engineering & Manufacturing North America
Transocean
Trinity Industries
Tronox
TRW Automotive
Tupperware Brands
Underwriters Laboratories
Unilever United States
Unisys
United Rentals
United States Cellular
United States Steel
United Technologies
UPS
URS
Valero Energy
Ventura Foods
Verizon
Vertex Pharmaceuticals
Viacom
Viad
Visteon
Vulcan Materials
VWR International
W.R. Grace
W.W. Grainger
Wal-Mart Stores
Walt Disney
Waste Management
Wendy's Group
West Pharmaceutical Services
Westinghouse Electric
Weyerhaeuser
Whirlpool
Winnebago Industries
Worthington Industries
Wyndham Worldwide
Xerium Technologies

Xerox
Xilinx
Yum! Brands
Zimmer

Towers Watson 2013 CDB Energy Services Executive Database

AEI Services
AES
AGL Resources
Allete
Alliant Energy
Ameren
American Electric Power
Areva
ATC Management
Atmos Energy
Avista
BG US Services
Black Hills
Calpine
Capital Power Corporation
CenterPoint Energy
CH Energy Group
Cleco
CMS Energy
Colorado Springs Utilities
Consolidated Edison
CPS Energy
Crosstex Energy
Dominion Resources
DTE Energy
Duke Energy
Dynegy
Edison International
Edison Mission Energy
ElectriCities of North Carolina
Energen
Energy Future Holdings
Energy Northwest
Energy Solutions
Energy Transfer
Entergy
EQT Corporation
ERCOT
Exelon
FirstEnergy
First Solar
GDF SUEZ Energy North America
Grand River Dam Authority
Hunt Consolidated
Iberdrola USA
Idaho Power
Indianapolis Power & Light Company
Integrys Energy Group
ISO New England
ITC Holdings
Kinder Morgan
LG&E and KU Energy
MDU Resources
MidAmerican Energy
Midwest Independent Transmission System Operator
New York Independent System Operator
New York Power Authority
NextEra Energy
NiSource
Northeast Utilities
NorthWestern Energy
NV Energy
NW Natural
OCI Enterprises
OGE Energy
Oglethorpe Power
Ohio Valley Electric
Old Dominion Electric
Omaha Public Power
Otter Tail
Pacific Gas & Electric
People's Natural Gas
Pepco Holdings
Pinnacle West Capital
PJM Interconnection
PNM Resources
Portland General Electric
PPL
Proliance Holdings
Public Service Enterprise Group
Puget Energy
Salt River Project
SCANA
Sempra Energy
Southern Company Services
Southwest Gas
Spectra Energy
STP Nuclear Operating
SunCoke Energy
TECO Energy
Tennessee Valley Authority
TransCanada
UGI
UIL Holdings
Unitil
UNS Energy
URENCO USA
Vectren
Westar Energy
Williams Companies
Wisconsin Energy
Wolf Creek Nuclear
Xcel Energy

Towers Watson 2013 CSR Report on Top Management Compensation

AAA
ABX Air
Acuity
AFLAC
AgFirst
AGL Resources
AIG
Alere Health LLC
Alfa Laval, Inc.
Alpha Packaging
Alyeska Pipeline Service
American Career College
American Enterprise
American Greetings
American Heart Association
American Water Works
AmerisourceBergen
Ameristar Casinos
Ames True Temper
Amica Mutual Insurance
AOC
Applied Research Associates
Asahi Kasei Plastics N.A. Inc.
Ascend Performance Materials
Auto Club Group
Automobile Club of Southern California
Avis Budget Group
Avista
Bain & Company
Baxter
Baylor College of Medicine
Baylor Health Care System
B Braun Medical
Beaulieu
Bemis Manufacturing Company
Beneficial Bank
The Bergquist Company
Berwick Offray
Blue Cross Blue Shield of Louisiana
Blue Cross Blue Shield of South Carolina
Blue Cross Blue Shield of Tennessee
Blue Cross of Idaho
Bluestem Brands
BMW Manufacturing Corporation
The Board of Pensions
Boddie-Noell Enterprises
Bosch Packaging Services
Boston University
Boyd Gaming
Boy Scouts of America
Bradley
Brickman Group
Bridgepoint Education
Briggs & Stratton
Bristow Group
Brookdale Senior Living
Bryant University
Build-A-Bear Workshop
CACI International
Caelum Research Corporation
California Casualty Management
California Dental Association
California Institute of Technology
Calpine
Cambia Health Solutions
CareFirst BlueCross BlueShield
Carlson
CDM Smith
CEMEX, Inc.
Chelan County Public Utility District
Chicago Transit Authority
Children's Healthcare of Atlanta
Choice Hotels International
CHS
Church of Jesus Christ of Latter-day Saints
Cigna
City of Chicago
City of Garland
City of Greensboro
City of Houston
City of Las Vegas
City of Philadelphia
ClubCorp Inc
CNL Financial Group
Coca-Cola Bottling
Coca-Cola Refreshments
College of Saint Benedict/Saint John's University
College of St Scholastica
Colsa
CommScope
Community Coffee
Community Health Network
The Community Preservation Corporation
Computer Task Group
ConnectiCare Capital LLC
Copper Point
Corinthian Colleges
Cornell University
The Cosmopolitan of Las Vegas
Country Financial
Cox Enterprises
CPS Energy

CTI BioPharma
CTS Corporation
CUNA Mutual
David C. Cook
DaVita
Decurion
Delhaize America
Department of Defense
DePaul University
DeVry Education Group
Dickstein Shapiro
Diebold
Doherty Employer Services
Domino's Pizza
DSC Logistics
Duke Realty
Duke University & Health System
E A Sween Company
Ecova
Edison Mission Energy
Education Management
Edwards Lifesciences
EGS Global Solutions
Elizabeth Arden
EMCOR Group
Emerson Electric
Emory University
Energy Future Holdings
Energy Solutions
Entergy
Environmental Chemical Corp
Erie Insurance
ESCO Technologies
Etnyre International Ltd
Farm Credit Bank of Texas
Farm Credit Foundations
Federal Reserve Bank of Atlanta
Federal Reserve Bank of Boston
Federal Reserve Bank of Chicago
Federal Reserve Bank of Cleveland
Federal Reserve Bank of Dallas
Federal Reserve Bank of Minneapolis
Federal Reserve Bank of Philadelphia
Federal Reserve Bank of St. Louis
Federal Reserve Board
FedEx Express
FedEx Office
Ferguson Enterprises
Fermi National Accelerator Laboratory
Ferro
First American
First Solar
Fiserv
Fleetwood Group
Flexcon Company Inc
Flexible Steel Lacing
Flowserve
Fluor Federal Petroleum Operations
Fortune Brands Home & Security
Franklin International
Freeman Dallas
Freeport-McMoRan Copper & Gold
Froedtert Health
Gannett
GENCO
General Dynamics Information Technology
Genesis Energy
Gentiva Health Services
Georg Fischer Signet
Georgia Health Sciences Medical Center
Georgia Institute of Technology
G4S Secure Solutions (USA)
Gibraltar Steel Corporation
G&K Services
Godiva Chocolatier
GOJO Industries
Gold Eagle
Graco
Grande Cheese
Great American Insurance
Greyhound Lines
Grinnell Mutual Reinsurance
GuideStone Financial Resources
Harman International Industries
Harris Health System
Harvard Vanguard Medical Associates
Haynes International
Hazelden Foundation
HDR Inc
HD Supply
Health Net
H. E. Butt Grocery
Hendrick Medical Center
Hendrickson
Henry Ford Health Systems
Highlights for Children
Highway Equipment Company
Hilti Inc
Hilton
Hitachi Computer Products
HNI
HNTB
Hu-Friedy Manufacturing Company, Inc.
Hunter Industries
Huntington Memorial Hospital
ICF International
IDEX Corporation
IDEXX Laboratories
Information Management Service
Ingram Industries
Insperity
Institute for Defense Analyses
Institute of Electrical & Electronic Engineers (IEEE)
Integra Lifesciences
Intertape Polymer Corp
Iron Mountain
Irvine
Ithaca College
Ithaka Harbors
Itochu International
Jackson Hewitt
Jacobs Technology
Jarden
Jefferson Science Associates
J&J Worldwide Services
Johnson Outdoors
Joint Commission
J.R. Simplot
Judicial Council of California
Kelsey-Seybold Clinic
K. Hovnanian Companies
KI, Inc
KIK Custom Products
Kingston Technology
Knape & Vogt Mfg Company
Laboratory Corporation of America
Lake Federal Bank
Lake Region Medical
Lantech.com
Layne Christensen
LBrands
Legal & General America
Leggett and Platt
LG&E and KU Energy
Lieberman Research
Lighthouse International
Littelfuse
Little Lady Foods
L.L. Bean
Lower Colorado River Authority
LSG Sky Chefs
Luck Companies
Lutron Electronics
Magellan Health Services
Magna Seating
Malco Products Inc
Manpower
ManTech International
MAPFRE U.S.A.
Maricopa County Office of Mgmt & Budget
Maricopa Integrated Health System
Maritz
Marshfield Clinic
Maxwell Technologies
Mayo Clinic
McCain Foods USA
McGladrey LLP
Medical College of Wisconsin
MEGTEC Systems
Merit Medical Systems
Merrill
Metagenics
The Methodist Hospital System
MFS Investment Management.
MGM Resorts International
Miami Children's Hospital
Michael Baker
MidAtlantic Employers Association
Mine Safety Appliances
Miniature Precision Comps, Inc.
Minneapolis School District
Minnesota Management & Budget
Missouri Department of Conservation
Missouri Department of Transportation
Mitsubishi International
Molex
Morinda
MTS Systems
MultiPlan
Mutual of Omaha
National Academies
National Futures Association
National Interstate
National Louis University
Nature's Sunshine Products
Navy Exchange Enterprise
NBH Bank
NCCI Holdings
NCMIC
Nebraska Medical Center
Nebraska Public Power District
New York Community Bank
NiSource
The Nordam Group
Nordson Corporation
Northwestern Memorial Hospital
Norton Health Care
NRG Energy
NYU Langone Medical Center
Oerlikon Fairfield
Oglethorpe Power
Old Dominion Electric
Orbital Science Corporation
Oriental Trading Company
Panduit
Papa John's
Parsons Child & Family Center
Patterson Companies

Pattonair
Paychex
Paycor
Pearson
Pegasus Solutions
Penn State Hershey Medical Center
PM
PMA Companies
Port of Portland
POWER Engineers
Premera Blue Cross
Principal Financial Group
Project Management Institute
Property Casualty Insurers Association of America
QBE the Americas
Quality Bicycle Products
Rational Energies
Recology
Regency Centers
Regions Financial
Remedi SeniorCare
Renaissance Learning
Rexnord Corporation
RiceTec
Rice University
Rich Products
Ricoh Americas
Ricoh Electronics
Rite-Hite
Riverside Research Institute
RLI
Rollins
RTC
Salk Institute
Sally Beauty
Salt Lake County
Salt River Project
Samuel Roberts Noble Foundation
San Jamar
Sazerac Company
SCANA
S&C Electric
Schwan Food Company
Sealy
Seco Tools Inc
Securus Technologies Inc
Seneca Gaming Corporation
Sentara Healthcare
ServiceMaster Company
Shands HealthCare
Sharp Electronics
Simon Property Group Inc
Simpson Housing
Sitel
SJE-Rhombus
Smithfield Farmland
SMSC Gaming Enterprise
Snyder's Lance
Sole Technology, Inc.
Southeastern Freight Lines
South Jersey Gas
Southwest Gas
Space Dynamics Laboratory
Spectrum Health - Grand Rapids Hospitals
Stampin' Up!
Standard Motor Products
Staples
State Corporation Commission
St. Cloud Hospital
Steris
Stinger Ghaffarian Technologies
St Louis County Government
Stonyfield Farm Inc
Subaru of Indiana Automotive, Inc.
Syncada
Taubman Centers
Taylor
TDS Telecom
Tech Data
Tecolote Research Inc
Tele-Consultants
Texas Industries Inc
TIMET
TJX Companies
Total System Service (TSYS)
Transdev NA, Inc.
Transitions Optical
Travis County
Treasure Island Resort & Casino
Tribune
Tri-Met
Trinity Consultants Inc
Trinity Health
True Value Company
Tufts Health Plan
Turner Broadcasting
UMDNJ-Univ of Medicine & Dentistry
Underwriters Laboratories
UnitedHealthCare
United States Steel
Universal Studios Orlando
University Health System
University of Akron
University of Alabama at Birmingham
University of Arkansas for Medical Science
University of California, Berkeley
University of Chicago
University of Georgia
University of Houston
University of Michigan
University of Notre Dame
University of Pennsylvania
University of Rochester
University of Southern California
University of South Florida
University of St. Thomas
University of Texas at Austin
University of Texas Health Science Center at Houston
University of Texas Health Science Center of San Antonio
University of Wisconsin Medical Foundation
University Physicians Inc
UPS
URS
USG Corporation
Utah Transit Authority
UT Southwestern Medical Center
VACCO Industries
Vail Resorts Management
Valero Energy
Valspar
Vesuvius
Via Christi Health
Viejas Enterprises
Vi-Jon
Vita-Mix Corporation
Walgreen Co
Walter Energy
Washington University in St. Louis
Waste Management
Wawa
Wayne Farms
Wayne Memorial Hospital
W. C. Bradley
Wellmark BlueCross BlueShield
Wells' Dairy
West Bend Mutual Insurance Co
Western University of Health Sciences
Weston Solutions Inc
West Penn Allegheny Health System
West Virginia University Hospitals, Inc.
Wheaton Franciscan Healthcare
Whole Foods Market
Wilmer Cutler Pickering Hale and Dorr LLP
Windstream Communications
Winn-Dixie Stores
Wisconsin Physicians Service Insurance
The Wornick Company
Worthington Industries
Xtek Inc
Zimmer

Mercer 2013 Total Compensation Survey for the Energy Sector

A&A Tank Truck Co.
AGL Resources - AGL Services Company (Networks)
Access Midstream Partners, L.P.
Addax Petroleum US
Afren Resources USA, Inc.
Aker Solutions
Alliance Pipeline, Inc.
Alliant Energy Corporation
Alyeska Pipeline Service Company
Ameren Corporation
Ameren Corporation - Ameren Energy Marketing Co
Ameren Corporation - Ameren Energy Resources
Ameren Corporation - Ameren Illinois
Ameren Corporation - Ameren Missouri
American Transmission Company
Anadarko Petroleum Corporation
Apache Corporation
Associated Electric Cooperative, Inc.
Atlantic Power Corporation - Atlantic Power Holdings, Inc.
Atlantic Power Corporation - Atlantic Power Services, LLC
Atlantic Power Corporation - Ridgeline Energy, LLC
Atlas Energy, L.P.
Atlas Resource Partners, L.P.
Aux Sable Liquid Products, Inc.
BHP Billiton Petroleum
BOS Solutions, Inc.
Baker Hughes, Inc.
Basic Energy Services, LP
Baytex Energy USA, Ltd.
Boardwalk Pipeline Partners, LP
BreitBurn Energy Partners L.P.
BreitBurn Energy Partners L.P. - Breitburn Energy Company LP, Orcutt Facility
BreitBurn Energy Partners L.P. - Breitburn Energy Company LP, West Pico Facility
BreitBurn Energy Partners L.P. - Eastern Division
BreitBurn Energy Partners L.P. - Pacific Coast Energy Company LP

BreitBurn Energy Partners L.P. - Regional Operations-Bigler, Texas Operations
BreitBurn Energy Partners L.P. - Western Division, California Operations
BreitBurn Energy Partners L.P. - Western Division, Florida Operations
BreitBurn Energy Partners L.P. - Western Division, Wyoming Operations
Breitburn Energy Partners L.P. - Breitburn Energy Company LP
Brookfield Renewable Energy Partners, LP USA
Buckeye Partners, L.P.
CGG
CH2M Hill
CITGO Petroleum Corporation
CNPC USA
COG Operating, LLC
CPS Energy
CVR Energy, Inc. - CVR Refining LP
CVR Energy, Inc. - Coffeyville Resources Nitrogen Fertilizers, LLC
Calfrac Well Services Corporation
Calpine Corporation
Cameron International
Cameron International - Drilling and Production Systems
Cameron International - Process and Compression Systems
Cameron International - Valves & Measurement
Carrizo Oil & Gas, Inc.
Castleton Commodities International, LLC
CenterPoint Energy
Chesapeake Energy Corporation
Chesapeake Energy Corporation - Chesapeake Oilfield Services, Inc.
Chesapeake Energy Corporation - Hodges Trucking Company, L.L.C.
Chesapeake Energy Corporation - MidCon Compression, L.L.C.
Chesapeake Energy Corporation - Nomac Drilling, L.L.C.
Chesapeake Energy Corporation - Oilfield Trucking Solutions, Inc.
Chesapeake Energy Corporation - Performance Technologies, LLC
Chesapeake Energy Corporation - Thunder Oilfield Services, L.L.C.
Chief Oil & Gas, LLC
Cimarex Energy Co.
Citation Oil & Gas Corp.
Cobalt International Energy
Colonial Pipeline Company
ConocoPhillips
Core Laboratories
Crescent Point Energy US Corp.
Crosstex Energy Services, LP
Cumberland Gulf Group
DM Petroleum Operations
DTE Energy
DTE Energy Company - DTE Electric
DTE Energy Company - DTE Gas
Davis Petroleum Corp.
Denbury Resources, Inc.
Det Norske Veritas USA
Devon Energy Corporation
Dexco Polymers
Diamond Offshore Drilling, Inc.
Direct Energy
Dominion Resources, Inc.
Dominion Resources, Inc. - Dominion Energy
Dominion Resources, Inc. - Dominion Generation
Dominion Resources, Inc. - Dominion Virginia Power
Dresser-Rand Group, Inc.
Dresser-Rand Group, Inc. - Dresser-Rand New Equipment
Dresser-Rand Group, Inc. - Dresser-Rand Product Services
Dresser-Rand Group, Inc. - NAO
EDF Trading Resources, LLC
EOG Resources, Inc.
EP Energy, LLC
EV Energy Partners
EXCO Resources, Inc.
EXCO Resources, Inc. - EXCO Appalachia
EXCO Resources, Inc. - EXCO East TX/LA
EXCO Resources, Inc. - EXCO Permian/Rockies
EXCO Resources, Inc. - TGGT Holdings, LLC
Ecova, Inc.
Edison Mission Energy
ElectriCities of North Carolina, Inc.
Enbridge Employee Services, Inc.
Encana Oil & Gas (USA), Inc.
EnerVest Operating, LLC
EnerVest, Ltd.
Energen Corporation
Energen Corporation - Energen Resources Corporation
Energy Future Holdings Corporation
Energy Future Holdings Corporation - Luminant
Energy Future Holdings Corporation - TXU Energy
EnergySolutions
EnergySolutions - Commercial Services Group
EnergySolutions - Government Customer Group
Enerplus Resources (USA) Corporation
Eni US Operating Company, Inc.
Ensco plc
Ensco plc - North & South America Business Unit
Ensign United States Drilling, Inc.
Ensign United States Drilling, Inc. - California
Ensign United States Drilling, Inc. - Ensign Well Services, Inc.
Entergy
Entergy - Non-Regulated
Entergy - Regulated
Equal Energy US, Inc.
Explorer Pipeline Company
Exterran Holdings, Inc.
FTS International, Inc.
FTS International, Inc. - FTSI Logistics
FTS International, Inc. - FTSI Manufacturing
FTS International, Inc. - FTSI Proppants
Forest Oil Corporation
Forum Energy Technologies, Inc.
GDF SUEZ Energy Generation NA, Inc.
GDF SUEZ Energy North America, Inc.
GDF SUEZ Energy Resources NA, Inc.
GDF SUEZ Gas NA, LLC
Genesis Energy, LP
Gibson Energy (U.S.), Inc.
Gibson Energy, LLC
Great River Energy
Halcón Resources Corporation
Halliburton Company
Helix Energy Solutions Group
Helmerich & Payne, Inc.
Hercules Offshore, Inc. - Hercules Offshore Services, LLC
Hess Corporation
HighMount Exploration & Production, LLC
Hilcorp Energy Company
Hilcorp Energy Company - Harvest Pipeline Company
Hunt Consolidated - Hunt Oil Company
Husky Energy, Inc.
ION Geophysical Corporation
J-W Energy Company
J-W Energy Company - J-W Manufacturing Company
J-W Energy Company - J-W Measurement Company
J-W Energy Company - J-W Midstream Company
J-W Energy Company - J-W Operating Company
J-W Energy Company - J-W Power Company
J-W Energy Company - J-W Wireline Company
JX Nippon Oil Exploration (U.S.A.), Ltd.
Kinder Morgan, Inc.
Kosmos Energy, LLC
Laredo Petroleum Holdings, Inc.
Legacy Reserves, LP
Link Petroleum, Inc.
Linn Energy, LLC
MCX Exploration (USA), Ltd.
MDU Resources Group, Inc.
MDU Resources Group, Inc. - Fidelity Exploration & Production Company
MDU Resources Group, Inc. - Montana Dakota Utilities
MDU Resources Group, Inc. - WBI Energy, Inc.
Madison Gas And Electric Company
Magellan Midstream Holdings, LP
Magellan Midstream Holdings, LP - Pipeline/Terminal Division
Magellan Midstream Holdings, LP - Transportation
Marathon Oil Company
MarkWest Energy Partners LP
MarkWest Energy Partners LP - Gulf Coast Business Unit
MarkWest Energy Partners LP - Liberty Business Unit
MarkWest Energy Partners LP - Northeast Business Unit
MarkWest Energy Partners LP - Southwest Business Unit
Marquis Alliance Energy Group USA, Inc.
McMoRan Exploration Co.
MicroSeismic
Mitsui E&P USA, LLC

Murphy Oil Corporation
New York Power Authority
New York Power Authority - 500 MW Combined Cycle Plant
New York Power Authority - Blenheim-Gilboa Power Project
New York Power Authority - Clark Energy Center
New York Power Authority - Niagara Power Project
New York Power Authority - Richard M. Flynn Power Plant
New York Power Authority - St. Lawrence/FDR Power Project
Newfield Exploration Company
Nexen Petroleum U.S.A. Inc.
NiSource Inc.
NiSource Inc. - Columbia Gas Transmission L.L.C.
NiSource Inc. - Columbia Gas of Kentucky
NiSource Inc. - Columbia Gas of Massachusetts
NiSource Inc. - Columbia Gas of Ohio
NiSource Inc. - Columbia Gas of Pennsylvania
NiSource Inc. - Columbia Gas of Virginia
NiSource Inc. - NiSource Gas Transmission & Storage
NiSource Inc. - NiSource Midstream Services, L.L.C.
NiSource Inc. - Northern Indiana Public Service Company
Noble Corporation
Noble Energy, Inc.
NorthWestern Energy
Northwest Natural Gas
OCI Enterprises, Inc.
OGE Energy Corp.
OGE Energy Corp. - Enogex
OMNI Energy Services Corp.
ONEOK, Inc.
ONEOK, Inc. - Kansas Gas Services Division
ONEOK, Inc. - ONEOK Energy Services Company
ONEOK, Inc. - ONEOK Partners
ONEOK, Inc. - Oklahoma Natural Gas Division
ONEOK, Inc. - Texas Gas Services Division
Oasis Petroleum, Inc.
Occidental Petroleum Corporation
Oceaneering International, Inc. - Intervention Engineering
Oceaneering International, Inc.
Oceaneering International, Inc. - Americas
Oceaneering International, Inc. - Inspection
Oceaneering International, Inc. - Umbilical Solutions
PDC Energy
PJM Interconnection
PPL Corporation - LG&E and KU Energy, LLC
PacifiCorp
Parallel Petroleum, LLC
Parker Drilling Company
Pasadena Refining System, Inc.
Petrofac Training Services
Piedmont Natural Gas Company, Inc.
Pioneer Natural Resources Company
Plains All American Pipeline, L.P.
Plains All American Pipeline, L.P. - PAA Natural Gas Storage, L.P.
Plains Exploration & Production Company
Praxair, Inc.
Praxair, Inc. - Hydrogen-carbon Monoxide (HyCO)
Praxair, Inc. - North American Industrial Gases
Praxair, Inc. - Praxair Distribution, Inc.
Praxair, Inc. - Praxair Surface Technologies
Precision Drilling Corporation
Premier Natural Resources, LLC
Puget Sound Energy
QEP Resources, Inc.
R Lacy Services, Ltd.
RKI Exploration & Production, LLC
Range Resources Corp.
Reef Subsea
Regency Energy Partners LP
Repsol Services Company
Resolute Energy Corporation
Rosewood Resources, Inc.
Rosewood Resources, Inc. - Rosewood Services Company
Rowan Companies, Inc.
SCANA Corporation
SCANA Corporation - Carolina Gas Transmission Corporation
SCANA Corporation - PSNC Energy
SCANA Corporation - SC Electric & Gas
SM Energy Company
Saipem America, Inc.
Samson Energy Company, LLC
Samson Exploration
Samson Offshore
Sasol North America, Inc.
Saxon Drilling L.P.
Schlumberger Limited - Schlumberger Oilfield Services
Seadrill Americas, Inc.
SemGroup Corporation
SemGroup Corporation - Rose Rock Midstream
SemGroup Corporation - SemGas
Sempra Energy - Cameron LNG
Sempra Energy - Mobile Gas Service Corporation
Sempra Energy - Sempra Global
Sempra Energy - Sempra International, LLC
Sempra Energy - Sempra LNG
Sempra Energy - Sempra U.S. Gas & Power, LLC
Sempra Energy - Willmut Gas Company
ShawCor, Ltd. - Bredero Shaw, LLC
ShawCor, Ltd. - Canusa-CPS
ShawCor, Ltd. - DSG-Canusa
ShawCor, Ltd. - Flexpipe Systems
ShawCor, Ltd. - Guardian
ShawCor, Ltd. - Shaw Pipeline Services
ShawCor, Ltd. - ShawFlex
Southcross Energy Partners LP
Southern Company
Southern Company - Alabama Power Company
Southern Company - Georgia Power
Southern Company - Gulf Power Company
Southern Company - Mississippi Power Company
Southern Ute Indian Tribe - Southern Ute Indian Tribe Growth Fund
Southern Ute Indian Tribe - Aka Energy Group, LLC
Southern Ute Indian Tribe - Red Cedar Gathering Company
Southern Ute Indian Tribe - Red Willow Production Company
Southern Ute Indian Tribe - Southern Ute Alternative Energy
Southern Ute Indian Tribe - Southern Ute Utilities Division
Southwest Gas Corporation
Southwest Gas Corporation-Southern Nevada Division
Southwestern Energy Company
Spectra Energy Corp
Sprague Operating Resources, LLC
Stantec, Inc.
Statoil
Superior Energy Services, Inc.
Superior Energy Services, Inc. - Completion Services
Superior Energy Services, Inc. - Fluid Management
Superior Energy Services, Inc. - Well Solutions
Superior Energy Services, Inc. - Workstrings International
Superior Energy Services, Inc.- HB Rentals
T.D. Williamson, Inc.
TGS-NOPEC Geophysical Company
Talisman Energy, Inc. US
Technip USA, Inc.
Tellus Operating Group, LLC
Tenaris, Inc. USA
The Keane Group
The Keane Group - KS Drilling LP
The University of Texas System
The Williams Companies, Inc.
The Williams Companies, Inc. - Northeast Gathering & Processing
The Williams Companies, Inc. - Northwest Pipeline
The Williams Companies, Inc. - Williams Gas Pipeline (WGP)
Tomkins Corporation - Gates Corporation
Total E&P USA, Inc.
TransCanada Corporation
TransCanada Corporation - Energy Group
Transocean, Inc.
Turner & Townsend
Unit Corporation
Unit Corporation - Superior Pipeline Company, LLC
Unit Corporation - Unit Drilling Company
Unit Corporation - Unit Petroleum Company
Venari Resources, LLC
WGL Holdings, Inc. - Washington Gas
WISCO, Inc.
WPX Energy, Inc.
Weatherford - US Region
Whiting Petroleum Corporation
WorleyParsons Canada, Inc.
Xcel Energy, Inc.
Zedi, Inc. - Southern Flow

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Stockholder Information

Corporate Headquarters

MDU Resources Group, Inc.
Street Address: 1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address: P.O. Box 5650
Bismarck, ND 58506-5650

Telephone: 701-530-1000
Toll-Free Telephone: 866-760-4852
www.mdu.com

The company has filed as exhibits to its Annual Report on Form 10-K the CEO and CFO certifications as required by Section 302 of the Sarbanes-Oxley Act.

The company also submitted the required annual CEO certification to the New York Stock Exchange.

Common Stock

MDU Resources' common stock is listed on the NYSE under the symbol MDU. The stock began trading on the NYSE in 1948 and is included in the Standard & Poor's MidCap 400 index. Average daily trading volume in 2015 was 1,224,159 shares.

Common Stock Prices

	High	Low	Close
2015			
First Quarter	$24.51	$20.01	$21.34
Second Quarter	23.12	19.22	19.53
Third Quarter	19.73	16.15	17.20
Fourth Quarter	19.66	16.26	18.32
2014			
First Quarter	$35.10	$29.62	$34.31
Second Quarter	36.05	32.45	35.10
Third Quarter	35.41	27.35	27.81
Fourth Quarter	28.51	21.33	23.50

Dividend Reinvestment and Direct Stock Purchase Plan

The company's plan provides interested investors the opportunity to purchase shares of the company's common stock and to reinvest dividends without incurring brokerage commissions. For complete details, including an enrollment form, contact the stock transfer agent. Plan information also is available on the Wells Fargo Shareowner Services website: www.shareowneronline.com.

2016 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 8	March 10	April 1
Second Quarter	June 7	June 9	July 1
Third Quarter	September 6	September 8	October 1
Fourth Quarter	December 6	December 8	January 1, 2017

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT Tuesday, April 26, 2016
Montana-Dakota Utilities Co. Service Center
909 Airport Road
Bismarck, North Dakota

Shareholder Information and Inquiries

Registered shareholders have electronic access to their accounts by visiting www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and more. The stock transfer agent maintains stockholder account information.

Communications regarding stock transfer requirements, lost certificates, dividends or change of address should be directed to the stock transfer agent.

Company information, including financial reports, is available at www.mdu.com.

Shareholder Contact

Dustin J. Senger
Telephone: 866-866-8919
Email: investor@mduresources.com

Analyst Contact

Director of Investor Relations
Telephone: 701-530-1057

Transfer Agent and Registrar for All Classes of Stock and Dividend Reinvestment Plan

Wells Fargo Bank, N.A.
Stock Transfer Department
P.O. Box 64874
St. Paul, MN 55164-0874
Telephone: 651-450-4064
Toll-Free Telephone: 877-536-3553
www.shareowneronline.com

Transfer Agent and Registrar for Senior Notes

The Bank of New York Mellon
Corporate Trust Department
101 Barclay St. — 12W
New York, NY 10286

Independent Registered Public Accounting Firm

Deloitte & Touche LLP
50 S. Sixth St., Suite 2800
Minneapolis, MN 55402-1538

Note: This information is not given in connection with any sale or offer for sale or offer to buy any security.

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Building a Strong America®

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Trading Symbol: MDU
www.mdu.com

MDU LISTED NYSE