



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:

Report is required by: OAR
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 201 High Street SE Suite 100, Salem, OR 97301.

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 2 Approved
OMB No.1902-0028
(Expires 12/31/2020)

Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)



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)

Cascade Natural Gas Corporation

Year/Period of Report

End of 2017/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 from 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	<u>Reference</u> <u>Schedules Pages</u>
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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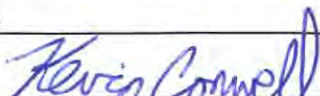
IDENTIFICATION

01 Exact Legal Name of Respondent Cascade Natural Gas Corporation	Year/Period of Report End of <u>2017/Q4</u>	
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 Kevin Conwell	06 Title of Contact Person Manager, 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 509-734-4524	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2017

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 Kevin Conwell	12 Title Manager, Accounting & Finance
13 Signature 	14 Date Signed 04/17/2018

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.

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 Recquired 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)			
	<input type="checkbox"/> Four copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared			

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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.

Kevin Conwell
 Manager, 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) No

Control Over Respondent

1. Report in column (a) the names of all corporations, partnerships, business trusts, and similar organizations that directly, indirectly, or jointly held control (see page 103 for definition of control) over the respondent at the end of the year. If control is in a holding company organization, report in a footnote the chain of organization.

2. If control is held by trustees, state in a footnote the names of trustees, the names of beneficiaries for whom the trust is maintained, and the purpose of the trust.

3. In column (b) designate type of control over the respondent. Report an "M" if the company is the main parent or controlling company having ultimate control over the respondent. Otherwise, report a "D" for direct, an "I" for indirect, or a "J" for joint control.

Line No.	Company Name (a)	Type of Control (b)	State of Incorporation (c)	Percent Voting Stock Owned (d)
1	MDU Resources Group, Inc. (MDUR)	M	DE	100.00
2	MDU Energy Capital, LLC	I	DE	100.00
3	Praire Cascade Energy Holdings, LLC (PCEH)	D	DE	100.00
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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	None				<i>Not used</i>
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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

<p>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:</p>	<p>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.</p> <p>Total:</p> <p>By Proxy:</p>	<p>3. Give the date and place of such meeting:</p>
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Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES			
		4. Number of votes as of (date):			
		Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	1,000	1,000		
6	TOTAL number of security holders	1	1		
7	TOTAL votes of security holders listed below	1,000	1,000		
8					
9					
10					
11	Cascade is a wholly-owned subsidiary of MDU Resources Group, Inc.				
12	MDU Resources Group, Inc.				
13	PO Box 5650				
14	Bismarck, ND 58506-5650				
15					
16					
17					
18					
19					
20					

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Cascade Natural Gas Corporation			
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 union employees increased 3.10% in April 2017.
9. None
10. None
11. OR Rate Increase (OPUC Order 16-477, Entered 12/12/2016, Rates Effective 03/01/2017)

Revenue Class	Increase	% Increase	Number of Customers
Residential	\$528,190.00	3.12%	60,662
Commercial	\$118,810.00	1.53%	9,901
Industrial	\$35,815.00	7.09%	128
Large Volume	\$17,185.00	7.09%	13
Other	\$ -	0.00%	39
Total	\$700,000.00	2.36%	70,743

12. Changes to Corporate Officers:

Jason Vollmer became Director taking over position previously held by Doran Schwartz
Garret Senger became Executive Vice President - Regulatory Affairs, Customer Service and Gas Supply

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Important Changes During the Quarter/Year			

None

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	997,637,482	922,694,564
3	Construction Work in Progress (107)	200-201	8,458,804	12,898,870
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	1,006,096,286	935,593,434
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		477,141,386	453,344,582
6	Net Utility Plant (Total of line 4 less 5)		528,954,900	482,248,852
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)		528,954,900	482,248,852
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	11,692,638	10,932,832
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)		11,894,668	11,134,862
31	CURRENT AND ACCRUED ASSETS			
32	Cash (131)		2,727,130	3,539,113
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		1,550	2,750
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		12,549,415	10,813,648
38	Other Accounts Receivable (143)		2,255,787	1,813,282
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		471,321	471,151
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		0	60,060
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)		8,026,535	7,223,893
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	587,529	126,656
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	2,230,775	1,705,164
54	Prepayments (165)	230	3,305,688	2,456,770
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		0	0
57	Rents Receivable (172)		0	0
58	Accrued Utility Revenues (173)		32,360,206	34,522,282
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 Assets - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		63,573,294	61,792,467
65	DEFERRED DEBITS			
66	Unamortized Debt Expense (181)		1,646,972	2,042,178
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	47,795,198	49,627,341
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		367	0
72	Clearing Accounts (184)		39,416	104,615
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	70,740,286	70,888,337
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)		785,271	826,242
78	Accumulated Deferred Income Taxes (190)	234-235	16,343,135	26,488,327
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		137,350,645	149,977,040
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		741,773,507	705,153,221

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	192,553,017	160,698,668
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	30,688,673	31,852,511
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	1,270,661	0
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		224,513,351	192,552,179
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	214,431,000	214,471,000
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)		214,431,000	214,471,000
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)		14,261,343	15,498,768
29	Accumulated Provision for Pensions and Benefits (228.3)		8,407,713	7,687,634
30	Accumulated Miscellaneous Operating Provisions (228.4)		48,270	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)		61,208,026	54,807,880
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		83,925,352	78,018,417
36	CURRENT AND ACCRUED LIABILITIES			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		17,300,000	0
39	Accounts Payable (232)		29,768,720	28,763,011
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		1,690,801	1,606,767
42	Customer Deposits (235)		904,903	874,939
43	Taxes Accrued (236)	262-263	8,002,294	8,418,892
44	Interest Accrued (237)		3,121,957	3,113,255
45	Dividends Declared (238)		3,300,000	4,160,000
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		0	3,542
49	Miscellaneous Current and Accrued Liabilities (242)	268	8,843,156	9,694,740
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)		72,931,831	56,635,146
56	DEFERRED CREDITS			
57	Customer Advances for Construction (252)		4,487,518	4,482,130
58	Accumulated Deferred Investment Tax Credits (255)		286,113	324,288
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	(980,392)	18,664,938
61	Other Regulatory Liabilities (254)	278	64,721,420	3,780,681
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)		52,078,937	100,067,346
65	Accumulated Deferred Income Taxes - Other (283)		25,378,377	36,157,096
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		145,971,973	163,476,479
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		741,773,507	705,153,221

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 column in 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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders 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 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 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	290,448,860	269,012,065	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	194,391,007	183,821,254	0	0
5	Maintenance Expenses (402)	317-325	7,645,195	5,729,642	0	0
6	Depreciation Expense (403)	336-338	24,014,068	22,501,731	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	3,032,663	2,736,728	0	0
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	0	0	0	0
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0	0	0
11	Amortization of Conversion Expenses (407.2)		0	0	0	0
12	Regulatory Debits (407.3)		0	0	0	0
13	(Less) Regulatory Credits (407.4)		0	0	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	29,055,993	25,926,633	0	0
15	Income Taxes-Federal (409.1)	262-263	(2,234,179)	4,283,371	0	0
16	Income Taxes-Other (409.1)	262-263	(129,101)	293,645	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	11,134,553	1,569,439	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)		(38,175)	(48,834)	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)		266,872,024	246,813,609	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		23,576,836	22,198,456	0	0

Statement of Income

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	0	0	290,448,860	269,012,065	0	0
3						
4	0	0	194,391,007	183,821,254	0	0
5	0	0	7,645,195	5,729,642	0	0
6	0	0	24,014,068	22,501,731	0	0
7	0	0	0	0	0	0
8	0	0	3,032,663	2,736,728	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	0	0	0	0
13	0	0	0	0	0	0
14	0	0	29,055,993	25,926,633	0	0
15	0	0	(2,234,179)	4,283,371	0	0
16	0	0	(129,101)	293,645	0	0
17	0	0	11,134,553	1,569,439	0	0
18	0	0	0	0	0	0
19	0	0	(38,175)	(48,834)	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	266,872,024	246,813,609	0	0
26	0	0	23,576,836	22,198,456	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)		23,576,836	22,198,456	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)		10,781	6,276	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)		568,811	610,340	0	0
38	Allowance for Other Funds Used During Construction (419.1)		177,923	361,162	0	0
39	Miscellaneous Nonoperating Income (421)		28,939	17,666	0	0
40	Gain on Disposition of Property (421.1)		0	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		786,454	995,444	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	299,157	232,468	0	0
46	Life Insurance (426.2)		(291,752)	0	0	0
47	Penalties (426.3)		0	1,001,184	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		128,933	128,203	0	0
49	Other Deductions (426.5)		1,097	1,437	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	137,435	1,363,292	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	1,106	3,164	0	0
53	Income Taxes-Federal (409.2)	262-263	(1,365)	(189,153)	0	0
54	Income Taxes-Other (409.2)	262-263	1,079	(12,967)	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)		820	(198,956)	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		648,199	(168,892)	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		11,403,441	11,144,573	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	454,448	171,932	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	505,177	653,866	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		253,406	284,975	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		12,150,631	11,726,367	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		12,074,404	10,303,197	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)		12,074,404	10,303,197	0	0

Name of Respondent			This Report Is:		Date of Report	Year/Period of Report
Cascade Natural Gas Corporation			(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		(Mo, Da, Yr) 12/31/2017	End of <u>2017/Q4</u>
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	-	-	23,576,836	22,198,456	-	-
28						
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	10,781	6,276	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	568,811	610,340	-	-
38	-	-	177,923	361,162	-	-
39	-	-	28,939	17,666	-	-
40	-	-	-	-	-	-
41	-	-	786,454	995,444	-	-
42						
43			-	-		
44			-	-		
45			299,157	232,468		
46			(291,752)	-		
47			-	1,001,184		
48			128,933	128,203		
49	-	-	1,097	1,437	-	-
50	-	-	137,435	1,363,292	-	-
51						
52			1,106.00	3,164		
53	-	-	(1,365)	(189,153)	-	-
54	-	-	1,079	(12,967)	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-	-	-	-	-
59	-	-	820	(198,956)	-	-
60	-	-	648,199	(168,892)	-	-
61						
62	-	-	11,403,441	11,144,573	-	-
63	-	-	454,448	171,932	-	-
64	-	-	40,971	40,971	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	505,177	653,866	-	-
69	-	-	(253,406)	(284,975)	-	-
70	-	-	12,150,631	11,726,367	-	-
71	-	-	12,074,404	10,303,197	-	-
72						
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	12,074,404	10,303,197	-	-

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 liability 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		1,270,661		
9	Total (lines 7 and 8)		1,270,661		
10	Balance of Account 219 at End of Current Quarter/Year		1,270,661		

Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify 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				10,303,197	10,303,197
5					
6					
7					
8			1,270,661		
9			1,270,661	12,074,404	13,345,065
10			1,270,661		

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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		31,852,511	38,204,913
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)		12,074,404	10,303,197
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)		13,238,242	16,655,599
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)		30,688,673	31,852,511
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		30,688,673	31,852,511
21	UNAPPROPRIATED UNDISTRICTED 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]

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)	12,074,404	10,303,197
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	27,046,732	25,238,459
5	Amortization of (Specify) (footnote details): Gas cost changes	(15,731,419)	(359,810)
6	Deferred Income Taxes (Net)	11,134,553	1,569,439
7	Investment Tax Credit Adjustments (Net)	(38,175)	(48,834)
8	Net (Increase) Decrease in Receivables	1,232,417	(3,644,653)
9	Net (Increase) Decrease in Inventory	(986,484)	(880,663)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	(3,573,373)	5,917,519
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	4,483,143	(983,591)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	35,641,798	37,111,063
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(71,112,784)	(56,530,179)
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	177,923	361,162
27	Other (footnote details): Net increase in customer advances for construction	416,891	406,901
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(70,873,816)	(56,484,440)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	(376,020)	(105,027)
32			
33	Investments in and Advances to Assoc. and Subsidiary Companies		
34	Contributions and Advances from Assoc. and Subsidiary Companies		
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies		
37			
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		

Statement of Cash Flows (continued)

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
40	Loans Made or Purchased		
41	Collections on Loans		
42			
43	Net (Increase) Decrease in Receivables		
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other (footnote details): SERP Assets	(22,527)	(20,180)
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(71,272,363)	(56,609,647)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	17,063,033	4,653
54	Preferred Stock		
55	Common Stock	32,000,000	8,000,000
56	Other (footnote details):	(14,266)	(5,284)
57	Net Increase in Short-term Debt (c)		
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	49,048,767	7,999,369
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(40,000)	(118,000)
63	Preferred Stock		
64	Common Stock	(131,385)	
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(14,060,000)	(16,640,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	34,817,382	(8,758,631)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	(813,183)	(28,257,215)
75			
76	Cash and Cash Equivalents at Beginning of Period	3,541,863	(31,799,078)
77			
78	Cash and Cash Equivalents at End of Period	2,728,680	3,541,863

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Cascade Natural Gas Corporation			
Notes to Financial Statements			

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
13. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

The accompanying notes relate to MDU Energy Capital, LLC and its subsidiary companies, while the financial statements in this FORM 2 Report reflect only the unconsolidated statements of Cascade Natural Gas Corporation. Cascade's subsidiary companies were dissolved as of 12/31/08 and do not have a material effect on the Notes to the Financial Statements.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

Definitions

The following abbreviations and acronyms used in these Financial Statements and Notes are 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
OPUC	Oregon Public Utility Commission
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
PRP	Potentially Responsible Party
RP	Rehabilitation plan
SEC	United States Securities and Exchange Commission
TCJA	Tax Cuts and Jobs Act
Washington DOE	Washington State Department of Ecology
WUTC	Washington Utilities and Transportation Commission

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

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 642,000 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 regulation by 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, 2017, up to the date of the issuance of these consolidated financial statements on March 30, 2018, that would require recognition or disclosure in the financial statements.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. In accordance with the accounting guidance on accounting for income taxes, entities must account for the effects of the change in tax laws or rates in the period of enactment. In the fourth quarter of 2017, the period of enactment, the Company performed a one-time revaluation of the net deferred tax liabilities to account for the reduction in the corporate tax rate from 35 percent to 21 percent effective January 1, 2018. For more information on the impacts of the TCJA on the year ended December 31, 2017, see Notes 3 and 7. The Company is currently reviewing the components of the TCJA and evaluating the impact on the Company's consolidated financial statements and related disclosures for 2018 and thereafter.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

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 \$685,000 and \$1.4 million as of December 31, 2017 and 2016, 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, 2017 and 2016 was \$740,000 and \$733,000, 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 lower of cost or net realizable value method at Intermountain. Natural gas in storage is expected to be used within one year and the value included in inventories was \$8.6 million and \$7.0 million at December 31, 2017 and 2016, 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 9.

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:

	2017	2016
	<i>(In thousands)</i>	
AFUDC - borrowed	\$ 336	\$ 493
AFUDC - equity	\$ 178	\$ 361

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.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

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

	2017	2016	Weighted Average Depreciable Life in Years
<i>(Dollars in thousands, as applicable)</i>			
Distribution plant	\$ 1,325,256	\$ 1,236,906	48
Transmission plant	96,320	95,896	52
Storage plant	25,988	25,345	23
General plant	113,138	107,917	17
Other plant	88,421	76,498	13
Non-depreciable plant	9,000	8,980	-
Construction in progress	12,825	14,220	-
Less: Accumulated depreciation and amortization	588,788	555,537	
Net property, plant and equipment	\$ 1,082,160	\$ 1,010,225	

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 2017 and 2016. 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, 2017 and 2016, there were no impairment losses recorded. At December 31, 2017, 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

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

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 4.9 percent, and a long-term growth rate projection of 3.5 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2017. 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.

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 \$62.6 million and \$70.1 million at December 31, 2017 and 2016, 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 \$27.8 million and \$25.5 million at December 31, 2017 and 2016, respectively. Natural gas

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

costs recoverable through rate adjustments were \$11.6 million and \$318,000 at December 31, 2017 and 2016, respectively.

Stock-based compensation

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also performs an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

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 by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. 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. 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 ratemaking 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.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

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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.

New accounting standards

Recently adopted accounting standards

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. The Company adopted the guidance on January 1, 2017, on a prospective basis. The guidance did not have a material effect on the Company's results of operations, financial position, cash flows or disclosures.

Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance affects the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. The Company early adopted the guidance on January 1, 2017. All amendments in the guidance that apply to the Company were adopted on a prospective basis resulting in no adjustments being made to retained earnings. The adoption of the guidance impacted the Consolidated Statement of Income and the Consolidated Balance Sheet in the first quarter of 2017 due to the taxes related to the stock-based compensation award that vested in February 2017 being recognized as income tax expense as compared to a reduction to additional paid-in capital under the previous guidance. Adoption of the guidance also increased the number of shares included in the diluted earnings per share calculation due to the exclusion of tax benefits in the incremental shares calculation. The change in the weighted average common shares outstanding - diluted did not result in a material effect on the earnings per common share - diluted.

Recently issued accounting standards not yet adopted

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. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was early adopted for the Company on January 1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

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The Company adopted the guidance on January 1, 2018, using the modified retrospective approach. The Company has substantially completed the evaluation of contracts and methods of revenue recognition under the previous accounting guidance and has not identified any material cumulative effect adjustments to be made to retained earnings. In addition, the Company will have expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers in the first quarter of 2018. The Company has reviewed substantially all of its revenue streams to evaluate the impact of this guidance and does not anticipate a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacts certain business processes and controls. As such, the Company has developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant.

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 was early adopted for the Company on January 1, 2018. The guidance was to be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which should be applied prospectively. The Company continues to evaluate the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures and does not anticipate a material impact.

Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. The Company early adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Clarifying the Definition of a Business In January 2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company early adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March 2017, the FASB issued guidance to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. The guidance requires the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net benefit costs shall be presented in the income statement separately from the

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service cost component and outside a subtotal of income from operations. The guidance also allows only the service cost component to be eligible for capitalization. The guidance was early adopted for the Company on January 1, 2018, including interim periods, on a retrospective basis for all periods presented with the exception of the capitalization of the service cost component which was adopted on a prospective basis.

The Company will reclassify all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income (expense) on the Consolidated Statements of Income for all years presented prior to January 1, 2018, beginning in the first quarter of 2018, with no impact to earnings. The guidance will not have a material impact on the Company's disclosures or cash flows.

Under FERC regulation, all components of net periodic benefit costs are currently eligible for capitalization. The Company's electric and natural gas distribution businesses have elected to continue to defer all components of net periodic benefit costs as regulatory assets or liabilities.

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases with terms of more than 12 months. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. This guidance will be early adopted for the Company on January 1, 2019, and should be applied using a retrospective approach with early adoption permitted. The Company continues to evaluate the potential impact the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures. The Company is planning to adopt the standard on January 1, 2019, utilizing the practical expedient that allows the Company to not reassess whether an expired or existing contract contains a lease, the classification of leases or initial direct costs.

In January 2018, the FASB issued a practical expedient for land easements under the new lease guidance. The practical expedient permits an entity to elect the option to not evaluate land easements under the new guidance if they existed or expired before the adoption of the new lease guidance and were not previously accounted for as leases under the previous lease guidance. Once an entity adopts the new guidance, the entity should apply the new guidance on a prospective basis to all new or modified land easements. The Company is currently evaluating the impact of the practical expedient.

On January 5, 2018, the FASB issued a proposed accounting standard update to the guidance that would allow an entity the option to adopt the guidance on a modified retrospective basis. Under the modified retrospective approach, an entity would recognize a cumulative effect adjustment of initially applying the guidance to the opening balance of retained earnings in the period of adoption. The Company is monitoring the status of the proposal.

Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step 2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step 1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting

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unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The guidance will be early adopted for the Company on January 1, 2020, and should be applied on a prospective basis with early adoption 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.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company is evaluating adoption of the guidance in the first quarter of 2018. At December 31, 2017, the Company had \$246,000 of stranded tax effects in the accumulated other comprehensive loss balance.

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 postretirement liability adjustments.

The postretirement liability adjustment in other comprehensive loss was \$1.1 million, net of tax of \$876,000, for the year ended December 31, 2017.

The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Twelve Months Ended December 31, 2017	Postretirement Liability Adjustment	Total Accumulated Other Comprehensive Loss
	(In thousands)	
Balance at December 31, 2016	\$ ---	\$ ---
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	(1,143)	(1,143)
Net current-period other comprehensive loss	(1,143)	(1,143)
Balance at December 31, 2017	\$ (1,143)	\$ (1,143)

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Twelve Months Ended December 31, 2016	Postretirement Liability Adjustment	Total Accumulated Other Comprehensive Loss
	(In thousands)	
Balance at December 31, 2015	\$ ---	\$ ---
Net current-period other comprehensive loss	---	---
Balance at December 31, 2016	\$ ---	\$ ---

NOTE 2 – GOODWILL

The carrying amount of goodwill for the years ended December 31, 2017 and 2016 remained unchanged at \$340.9 million. 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 *	2017	2016
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(c)	\$ 47,953	\$ 53,846
Manufactured gas plant sites remediation (a)	Largely determined upon filing	18,213	17,787
Natural gas costs recoverable through rate adjustments	Up to 1 year	11,596	318
Deferred costs - MAOP (a)	-	6,572	2,220
Taxes recoverable from customers (a)	Over plant lives	2,780	11,461
Long-term debt refinancing costs (a)	Up to 20 years	837	950
Conservation activities (a)	-	---	4,014
Other (a)	Largely determined upon filing	387	513
Total regulatory assets		88,338	91,109
Regulatory liabilities:			
Plant removal costs (b)		115,046	114,074
Taxes refundable to customers		82,472	4,618
Natural gas costs refundable through rate adjustments		27,821	25,531
Conservation activities (b)		5,898	314
Other (b)		6,011	5,168
Total regulatory liabilities		237,248	149,705
Net regulatory position		\$(148,910)	\$ (58,596)

* 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, 2017 and 2016, approximately \$84.7 million and \$79.6 million, respectively, of regulatory assets were not earning a rate of return.

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In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. The revaluation of the Company's regulatory deferred tax assets and liabilities are being deferred as the Company works with the various regulators on a plan for amounts expected to be returned to customers, as discussed in Note 10. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of \$8.2 million in taxes recoverable from customers and an increase of \$78.9 million in taxes refundable to customers. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

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 \$3.6 million and \$3.3 million as of December 31, 2017 and 2016, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2017 and 2016 were \$430,000 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.

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.

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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, 2017 and 2016, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2017, 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, 2017
	<i>(In thousands)</i>			
Assets:				
Money market funds	\$ ---	\$ 363	\$ ---	\$ 363
Insurance contract*	---	3,583	---	3,583
Total assets measured at fair value	\$ ---	\$ 3,946	\$ ---	\$ 3,946

* The insurance contract invests approximately 49 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 14 percent in common stock of mid-cap companies, 11 percent in common stock of small-cap companies, 2 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at December 31, 2016, 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, 2016
	<i>(In thousands)</i>			
Assets:				
Money market funds	\$ ---	\$ 112	\$ ---	\$ 112
Insurance contract*	---	3,284	---	3,284
Total assets measured at fair value	\$ ---	\$ 3,396	\$ ---	\$ 3,396

* The insurance contract invests approximately 52 percent in fixed-income investments, 22 percent in common stock of large-cap companies, 13 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 1 percent in target date investments and 2 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:

	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	<i>(In thousands)</i>			
Long-term debt	\$ 519,601	\$ 566,811	\$ 488,297	\$ 515,897

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

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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, 2017	Amount Outstanding at December 31, 2016	Letters of Credit at December 31, 2017	Expiration Date
<i>(Dollars in millions)</i>						
Cascade Natural Gas Corporation	Revolving credit agreement	\$ 75.0 (a)	\$ 17.3	\$ ---	\$ 2.2 (b)	4/24/20
Intermountain Gas Company	Revolving credit agreement	\$ 85.0 (c)	\$ 40.0	\$ 20.9	\$ ----	4/24/20

(a) Certain provisions allow for increased borrowings, up to a maximum of \$100.0 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 \$110.0 million.

The following includes information related to the preceding table.

Long-term debt

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.

On April 25, 2017, Cascade amended its revolving credit agreement to increase the borrowing limit from \$50.0 million to \$75.0 million and extend the termination date from July 9, 2018 to April 24, 2020. 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.

On April 25, 2017, Intermountain amended its revolving credit agreement to increase the borrowing limit from \$65.0 million to \$85.0 million and extend the termination date from July 13, 2018 to April 24, 2020. 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

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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:

	2017	2016
	<i>(In thousands)</i>	
Senior Notes at a weighted average rate of 4.39%, due on dates ranging from September 18, 2018 to January 15, 2055	\$ 390,273	\$ 395,546
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	50,000
Credit agreement at a rate of 3.71%, due on April 24, 2020	57,300	20,850
Other note at a rate of 5.25%, due on February 1, 2035	24,431	24,471
Unamortized debt issuance costs	(2,403)	(2,570)
Total long-term debt	519,601	488,297
Less current maturities	5,273	40,273
Net long-term debt	\$ 514,328	\$ 448,024

Schedule of Debt Maturities Long-term debt maturities, which excludes unamortized debt issuance costs and discount for the five years and thereafter following December 31, 2017, were as follows:

	2018	2019	2020	2021	2022	Thereafter
	<i>(In thousands)</i>					
Long-term debt maturities	\$5,273	---	\$72,300	---	\$11,500	\$432,931

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

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

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A reconciliation of the Company's liability for the years ended December 31 was as follows:

	2017	2016
	<i>(In thousands)</i>	
Balance at beginning of year	\$ 124,418	\$ 116,210
Liabilities incurred	8,743	2,371
Liabilities settled	(924)	(898)
Accretion expense (related to regulatory assets)	7,125	6,735
Balance at end of year	\$ 139,362	\$124,418

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, 2017 and 2016 was \$36,314 and \$18,462, respectively.

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

	2017	2016
	<i>(In thousands)</i>	
Current:		
Federal	\$ 3,997	\$ 5,511
State	1,196	430
	5,193	5,941
Deferred:		
Income taxes –		
Federal	11,841	(897)
State	(127)	250
Investment tax credit - net	(253)	(1,020)
	11,461	(1,667)
Total income tax expense	\$ 16,654	\$ 4,274

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes associated with the non-regulated operations were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax expense of \$3.5 million for the year ended December 31, 2017. Included in the tax expense was \$246,000 related to amounts in accumulated other comprehensive loss.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators on a plan for amounts

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expected to be returned to customers, as discussed in Notes 3 and 10. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of \$87.1 million in the fourth quarter of 2017. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

The changes included in the TCJA are broad and complex. While the Company was able to make reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities, it may be affected by other analyses related to the TCJA, including, but not limited to, the state tax effect of adjustments to federal temporary differences. The final transition impacts of the TCJA may differ from amounts disclosed, possibly materially, due to, among other things, changes in interpretations, legislative action to address questions, changes in accounting standards for income taxes or related interpretations, or updates or changes to estimates the Company has utilized to calculate the transition impacts. The SEC has issued rules, which were affirmed by the FASB as also acceptable for non-public entities, that would allow for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company currently anticipates finalizing and recording any resulting adjustments by December 31, 2018, which will be included in income from continuing operations.

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

	2017	2016
	<i>(In thousands)</i>	
Deferred tax assets:		
Contingency reserve	\$ 3,198	\$ 5,258
Accrued pension costs	7,991	13,389
Other	7,154	10,434
Total deferred tax assets	18,343	29,081
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	85,449	163,432
Postretirement	11,996	21,813
Other	8,622	7,257
Total deferred tax liabilities	106,067	192,502
Net deferred income tax liability	\$ (87,724)	\$ (163,421)

As of December 31, 2017 and 2016, no valuation allowance has been recorded associated with the above deferred tax assets.

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The following table reconciles the change in the net deferred income tax liability from December 31, 2016, to December 31, 2017, to deferred income tax expense:

	2017
	<i>(In thousands)</i>
Change in net deferred income tax liability from the preceding table	\$ (75,697)
Deferred taxes associated with TCJA enactment	87,036
Other	122
Deferred income tax expense for the period	\$ 11,461

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,	2017		2016	
	Amount	%	Amount	%
	<i>(Dollars in thousands)</i>			
Computed tax at federal statutory rate	\$ 12,710	35.0	\$ 6,462	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	1,110	3.1	268	1.5
TCJA revaluation	3,236	8.9	---	---
Flow-through	580	1.6	(193)	(1.0)
TCJA revaluation related to accumulated other comprehensive income	246	0.7	---	---
AFUDC equity	(503)	(1.4)	---	---
Amortization of deferral of investment tax credit	(253)	(0.7)	(2,281)	(12.4)
Resolution of tax matters and uncertain tax positions	(197)	(0.5)	(406)	(2.2)
Other	(275)	(0.8)	424	2.3
Total income tax expense	\$ 16,654	45.9	\$ 4,274	23.2

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 2014. As of December 31, 2017, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2013.

The Company had no unrecognized tax benefits (excluding interest) for the years ended December 31, 2017 and 2016.

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2017 and 2016, the Company recognized approximately \$3,000 and (\$25,000), respectively, of interest (income) expense in

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income tax expense. The Company had accrued liabilities of approximately \$16,000 and \$12,000 at December 31, 2017 and 2016, respectively, for the payment of interest.

NOTE 8 – CASH FLOW INFORMATION

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

	2017	2016
	<i>(In thousands)</i>	
Interest, net of AFUDC-borrowed of \$336 and \$493 in 2017 and 2016, respectively	\$ 23,586	\$ 22,799
Income taxes paid, net	\$ 3,092	\$ 6,633

Noncash investing transactions at December 31 were as follows:

	2017	2016
	<i>(In thousands)</i>	
Property, plant and equipment additions in accounts payable	\$ 7,661	\$ 5,246

NOTE 9 – EMPLOYEE BENEFIT PLANS

Pension and other postretirement benefit plans

The Company has a noncontributory qualified defined benefit pension plan and other postretirement benefit plans for certain eligible employees. Prior to 2016, 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, 2017 and 2016 and amounts recognized in the Consolidated Balance Sheets at December 31, 2017 and 2016, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
	<i>(In thousands)</i>			
Change in benefit obligation:				
Benefit obligation at beginning of year	\$ 91,107	\$ 91,054	\$ 20,499	\$ 20,527
Service cost	---	---	210	214
Interest cost	3,406	3,592	730	793
Plan participants' contributions	---	---	392	400
Actuarial (gain) loss	3,910	892	(63)	183
Benefits paid	(5,567)	(4,431)	(1,294)	(1,618)
Benefit obligation at end of year	92,856	91,107	20,474	20,499
Change in net plan assets:				
Fair value of plan assets at beginning of year	78,920	76,943	20,077	19,884
Actual gain on plan assets	11,065	6,408	2,230	1,013
Employer contribution	---	---	269	398
Plan participants' contributions	---	---	392	400
Benefits paid	(5,567)	(4,431)	(1,294)	(1,618)
Fair value of net plan assets at end of year	84,418	78,920	21,674	20,077
Funded status – over (under)	\$ (8,438)	\$ (12,187)	\$ 1,200	\$ (422)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	\$ ---	\$ ---	\$ 2,415	\$ 1,322
Other liabilities (noncurrent)	(8,438)	(12,187)	(1,215)	(1,744)
Net amount recognized	\$ (8,438)	\$ (12,187)	\$ 1,200	\$ (422)
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	\$ 40,552	\$ 44,101	\$ 4,903	\$ 6,644
Prior service credit	---	---	(1,551)	(1,706)
Total	\$ 40,552	\$ 44,101	\$ 3,352	\$ 4,938

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.

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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:

	2017	2016
	<i>(In thousands)</i>	
Projected benefit obligation	\$ 92,856	\$91,107
Accumulated benefit obligation	\$ 92,856	\$91,107
Fair value of plan assets	\$ 84,418	\$78,920

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	
	2017	2016	2017	2016
	<i>(In thousands)</i>			
Components of net periodic benefit cost (credit):				
Service cost	\$ ---	\$ ---	\$ 210	\$ 214
Interest cost	3,406	3,592	730	793
Expected return on assets	(4,978)	(5,039)	(1,119)	(1,109)
Amortization of prior service credit	---	---	(156)	(156)
Recognized net actuarial loss	1,373	1,270	568	676
Net periodic benefit cost (credit), including amount capitalized	(199)	(177)	233	418
Less amount capitalized	(45)	(46)	76	130
Net periodic benefit cost (credit)	(154)	(131)	157	288
Other changes in plan assets and benefit obligations recognized in regulatory assets (liabilities):				
Net (gain) loss	(2,176)	(478)	(1,174)	279
Amortization of actuarial loss	(1,373)	(1,270)	(568)	(676)
Amortization of prior service credit	---	---	156	156
Total recognized in regulatory liabilities	(3,549)	(1,748)	(1,586)	(241)
Total recognized in net periodic benefit cost (credit) and regulatory assets (liabilities)	\$ (3,703)	\$ (1,879)	\$ (1,429)	\$ 47

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost in 2018 is \$1.5 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 2018 are \$424,000 and \$180,000, 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	
	2017	2016	2017	2016
Discount rate	3.40%	3.86%	3.38%	3.83%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%

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

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Discount rate	3.86%	4.03%	3.83%	4.04%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%

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, 2017, 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 20 percent to 25 percent equity securities and 75 percent to 80 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:

	2017	2016
Health care trend rate assumed for next year	7.5% - 8.5%	9.0% - 10.7%
Health care cost trend rate – ultimate	4.5%	4.5%
Year in which ultimate trend rate achieved	2024	2024

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, 2017:

	1 Percentage Point Increase	1 Percentage Point Decrease
	<i>(In thousands)</i>	
Effect on total of service and interest cost components	\$ 48	\$ (41)
Effect on postretirement benefit obligation	\$ 1,246	\$ (1,077)

Outside investment managers manage the Company's pension and postretirement assets. 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

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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.

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.

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, 2017 and 2016, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2017, Using			Balance at December 31, 2017
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	<i>(In thousands)</i>			
Assets:				
Cash equivalents	\$ ---	\$ 909	\$ ---	\$ 909
Equity securities:				
U.S. companies	3,179	---	---	3,179
International companies	421	---	---	421
Collective and mutual funds*	40,929	16,139	---	57,068
Corporate bonds	---	17,855	---	17,855
Municipal bonds	---	4,011	---	4,011
U.S. Government securities	247	---	---	247
Total assets measured at fair value	\$ 44,776	\$ 38,914	\$ ---	\$ 83,690

* *Collective and mutual funds invest approximately 31 percent in common stock of international companies, 28 percent in corporate bonds, 19 percent in common stock of large-cap U.S. companies, 7 percent in cash equivalents, 1 percent in U.S. Government securities and 14 percent in other investments.*

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	Fair Value Measurements at December 31, 2016, 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, 2016
	<i>(In thousands)</i>			
Assets:				
Cash equivalents	\$ ---	\$ 1,502	\$ ---	\$ 1,502
Equity securities:				
U.S. companies	2,685	---	---	2,685
International companies	375	---	---	375
Collective and mutual funds*	38,348	15,157	---	53,505
Corporate bonds	---	16,252	---	16,252
Municipal bonds	---	2,603	---	2,603
U.S. Government securities	1,030	484	---	1,514
Total assets measured at fair value	\$ 42,438	\$ 35,998	\$ ---	\$ 78,436
* <i>Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in corporate bonds, 20 percent in common stock of large-cap U.S. companies, 8 percent in cash equivalents, 7 percent in common stock in U.S. Government securities, and 15 percent in other investments.</i>				

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.

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, 2017 and 2016, there were no transfers between Levels 1 and 2.

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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, 2017, 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, 2017
<i>(In thousands)</i>				
Assets:				
Cash equivalents	\$ ---	\$ 1,181	\$ ---	\$ 1,181
Equity securities:				
U.S. companies	891	---	---	891
International companies	4	---	---	4
Insurance contract*	3	19,595	---	19,598
Total assets measured at fair value	\$ 898	\$ 20,776	\$ ---	\$ 21,674

* The insurance contract invests approximately 38 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 21 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 9 percent in other investments.

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Fair Value Measurements
at December 31, 2016, 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, 2016
<i>(In thousands)</i>				
Assets:				
Cash equivalents	\$ ---	\$ 115	\$ ---	\$ 115
Equity securities:				
U.S. companies	947	---	---	947
International companies	5	---	---	5
Insurance contract*	13	18,997	---	19,010
Total assets measured at fair value	\$ 965	\$ 19,112	\$ ---	\$ 20,077

* The insurance contract invests approximately 38 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 20 percent in U.S. Government securities, 9 percent in mortgage-backed securities, and 8 percent in other investments.

The Company does not expect to contribute to its defined benefit pension plan and expects to contribute approximately \$168,000 to its postretirement benefit plans in 2018.

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
<i>(In thousands)</i>			
2018	4,781	1,270	2
2019	4,917	1,264	1
2020	5,044	1,206	1
2021	5,125	1,203	1
2022	5,241	1,224	1
2023-2027	27,212	6,229	2

Nonqualified benefit plans

In addition to the qualified defined pension benefit plan 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, upon death, to their beneficiaries 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,

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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 benefit increases. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was \$1.0 million and \$1.1 million in 2017 and 2016, respectively, which reflects a curtailment gain of \$234,000 in the first quarter of 2016. The total projected benefit obligation for these plans was \$14.2 million at December 31, 2017 and 2016. The accumulated benefit obligation for these plans was \$14.2 million at December 31, 2017 and 2016. A weighted average discount rate of 3.3 percent and 3.7 percent at December 31, 2017 and 2016, respectively, was used to determine benefit obligations. No rate of compensation increase was used to determine the benefit obligation at December 31, 2017 and 2016, due to the plans being frozen. A weighted average discount rate of 3.7 percent and 3.8 percent for the years ended December 31, 2017 and 2016, respectively, and a rate of compensation increase of 4.0 percent for the year ended December 31, 2016 was used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate \$1.1 million in 2018; \$1.1 million in 2019; \$1.1 million in 2020; \$1.0 million in 2021; \$924,000 in 2022 and \$4.4 million for the years 2023 through 2027.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2017 and 2016 were \$85,000 and \$45,000, respectively.

The Company had investments of \$11.8 million and \$11.1 million at December 31, 2017 and 2016, respectively, consisting of equity securities of \$3.1 million and \$2.9 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of \$7.8 million and \$7.5 million, respectively, and other investments of \$903,000 and \$632,000, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred by the Company under these plans were \$3.8 million in 2017 and \$4.6 million in 2016.

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

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The Company's participation in this plan is outlined in the following table. The most recent Pension Protection Act zone status available in 2017 and 2016 is for the plan's year-end at December 31, 2016, and December 31, 2015, 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		FIP/RP Status Pending/Implemented	Contributions		Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
		2017	2016		2017	2016		
(In thousands)								
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2017	Green as of 5/31/2016	No	\$ 1,156	\$ 1,221	No	09/30/2019

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, 2016 and 2015.

NOTE 10 – REGULATORY MATTERS

The Company regularly reviews the need for natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The jurisdictions in which the Company provides service have requested the Company furnish plans for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details on each jurisdiction's request.

IPUC

On August 12, 2016, Intermountain filed an application with the IPUC for a natural gas rate increase of approximately \$10.2 million annually or approximately 4.1 percent above current rates. The request included rate recovery associated with increased investment in facilities and increased operating expenses. On January 17, 2017, Intermountain provided the IPUC with an updated revenue request of approximately \$9.4 million. On April 28, 2017, the IPUC issued an order approving an increase of approximately \$4.1 million or approximately 1.6 percent above current rates based on a 9.5 percent return on equity effective with service rendered on and after May 1, 2017. On May 18, 2017, Intermountain filed a petition for reconsideration with the IPUC requesting the reconsideration of certain items denied in the order dated April 28, 2017. On June 15, 2017, the IPUC granted the request for reconsideration. On August 17, 2017, Intermountain, the IPUC staff and the interveners of the case filed a stipulation and settlement resolving all issues. The stipulation and settlement reflected an increase of approximately \$1.2 million or 1.36 percent more in annual revenue than the amounts approved on April 28, 2017, as well as changes in billing determinants. The total annual increase in revenue of approximately \$6.7 million was approved by the IPUC on September 14, 2017, with rates effective October 1, 2017.

On January 17, 2018, the IPUC issued a general order initiating the investigation of the impacts of the TCJA. The order required the tax rate reduction to be deferred as a regulatory liability and for companies to report on the expected impacts of the TCJA by March 30, 2018. Initial filings addressing the impacts of the TCJA were submitted on March 23, 2018.

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OPUC

On September 29, 2017, Cascade filed an application with the OPUC for an annual pipeline replacement safety cost recovery mechanism of approximately \$784,000 or approximately 1.2 percent of additional revenue. The requested increase included incremental pipeline replacement investments associated with qualifying pipeline integrity projects. On March 6, 2018 the application was withdrawn.

On December 29, 2017, Cascade filed a request with the OPUC to use deferral accounting for the 2018 net benefits associated with the implementation of the TCJA. The matter is pending before the OPUC.

WUTC

On May 31, 2017, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of approximately \$1.6 million or approximately .75 percent of additional revenue. The requested increase included incremental pipeline replacement investments associated with qualifying pipeline integrity projects. On October 12, 2017, Cascade filed a required update revising the request to approximately \$1.3 million or approximately .61 percent of additional revenue and on October 26, 2017, the WUTC approved the order with rates effective November 1, 2017.

On August 31, 2017, Cascade filed an application with the WUTC for a natural gas rate increase of approximately \$5.9 million annually or approximately 2.7 percent above current rates. The requested increase included costs associated with increased infrastructure investment and the associated operating expenses. Also included in the request was recovery of operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On January 3, 2018, the WUTC filed a bench request requiring Cascade to provide information related to the impacts of the TCJA on Cascade's revenue requirement and a proposed ratemaking treatment of those impacts. On January 12, 2018, Cascade filed a response to the bench request reducing the revenue requirement to approximately \$1.7 million annually, which included the estimated impacts of the TCJA. On March 23, 2018, Cascade filed rebuttal testimony, which included the impacts of the TCJA and an updated revenue requirement reflecting a decrease of approximately \$1.7 million annually. This matter is pending before the WUTC.

NOTE 11 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business. 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. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories. The Company accrued liabilities of \$14.3 million and \$15.5 million for contingencies including litigation and environmental matters at December 31, 2017 and 2016, respectively. This includes amounts that may have been accrued for matters discussed in Environmental matters within this note. The Company will

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continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

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. 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. The total estimated cost for the selected remediation, including long-term maintenance, is approximately \$3.5 million of which \$400,000 has been incurred. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade has paid 50 percent of the ongoing investigation and design costs and anticipates its proportional share of the final costs could be approximately 50 percent. Cascade has an accrual balance of \$1.6 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, 2016 and December 1, 2017.

The second claim is for contamination at the Bremerton Gasworks Superfund 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 DOE 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. Current estimates for the cost to complete the remedial investigation and feasibility study are approximately \$7.6 million of which \$1.7 million has been incurred. Cascade has accrued \$5.9 million for the remedial investigation and feasibility study as well as \$6.4 million for remediation of this site; however, the accrual for remediation costs will be reviewed and adjusted, if necessary, after completion of the remedial investigation and feasibility study. 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. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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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 DOE 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 not recorded an accrual for this site.

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 \$45,000 and \$36,000 in 2017 and 2016, respectively, for the Eugene defense costs and \$1.2 million and \$618,000 in 2017 and 2016, respectively, for the Bremerton defense costs. To the extent these claims are not covered by insurance, Cascade intends to 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, 2017, were:

	2018	2019	2020	2021	2022	Thereafter
				(In thousands)		
Operating leases	\$399	\$370	\$250	\$209	\$91	\$328

Rent expense was \$546,000 and \$541,000 for the year ended December 31, 2017 and 2016, 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. The commitment terms vary in length, up to 43 years. The commitments under these contracts as of December 31, 2017, were:

	2018	2019	2020	2021	2022	Thereafter
				(In thousands)		
Purchase commitments	\$168,558	\$116,055	\$91,683	\$87,423	\$75,717	\$628,962

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2017 and 2016, respectively, were approximately

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2017 and 2016

\$162.8 million and \$184.8 million.

Guarantees

Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study. At December 31, 2017, the fixed maximum amount guaranteed under this letter of credit was \$2.2 million, which is scheduled to expire in 2018. There were no amounts outstanding under this letter of credit at December 31, 2017.

NOTE 12 – 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 \$32.0 million and \$35.8 million for the years ended December 31, 2017 and 2016, respectively and the amount charged for services received from the Company was \$1.1 million and \$966,000 for the years ended December 31, 2017 and 2016, respectively.

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

	2017	2016
	<i>(In thousands)</i>	
Accounts receivable	\$ 2	\$ 84
Accounts payable	2,634	2,584
Dividend payable	4,800	4,800
Deferred charges and other assets - other	6,719	5,900
Deferred credits and other liabilities - other	1,676	1,615

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2017 and 2016, respectively, was \$676,000 and \$716,000, net of income taxes of \$432,000 and \$458,000, respectively. As of December 31, 2017, total remaining unrecognized compensation expense related to stock-based compensation was approximately \$1.1 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

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)	954,960,215
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	42,677,267
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	997,637,482
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	8,458,804
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	1,006,096,286
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	477,141,385
15	Net Utility Plant (Total of lines 13 and 14)	528,954,901
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	463,301,410
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	13,839,975
22	TOTAL In Service (Total of lines 18 thru 21)	477,141,385
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)	477,141,385

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		954,960,215		
4				
5				
6		42,677,267		
7				
8		997,637,482		
9				
10				
11		8,458,804		
12				
13		1,006,096,286		
14		477,141,385		
15		528,954,901		
16				
17				
18		463,301,410		
19				
20				
21		13,839,975		
22		477,141,385		
23				
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32				
33		477,141,385		

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	33,571,462	9,661,779
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	33,935,353	9,661,779
6	PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands		
9	325.2 Producing Leaseholds		
10	325.3 Gas Rights		
11	325.4 Rights-of-Way		
12	325.5 Other Land and Land Rights		
13	326 Gas Well Structures		
14	327 Field Compressor Station Structures		
15	328 Field Measuring and Regulating Station Equipment		
16	329 Other Structures		
17	330 Producing Gas Wells-Well Construction		
18	331 Producing Gas Wells-Well Equipment		
19	332 Field Lines		
20	333 Field Compressor Station Equipment		
21	334 Field Measuring and Regulating Station Equipment		
22	335 Drilling and Cleaning Equipment		
23	336 Purification Equipment		
24	337 Other Equipment		
25	338 Unsuccessful Exploration and Development Costs		
26	339 Asset Retirement Costs for Natural Gas Production and		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8		
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights		
30	341 Structures and Improvements		
31	342 Extraction and Refining Equipment		
32	343 Pipe Lines		
33	344 Extracted Products Storage Equipment		

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1				
2				152,066
3				211,825
4				43,233,241
5				43,597,132
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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)
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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)
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	21,858,600	385,973
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment	192,301	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant	87,147	864
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	23,388,673	386,837
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,486,528	155,969
95	375 Structures and Improvements	1,459,328	5,816
96	376 Mains	428,486,175	37,322,931
97	377 Compressor Station Equipment	2,097,767	
98	378 Measuring and Regulating Station Equipment-General	28,118,944	3,753,497
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	214,076,819	14,574,925
101	381 Meters	56,271,855	2,733,170
102	382 Meter Installations	31,328,381	1,560,254
103	383 House Regulators	10,387,457	656,173
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	10,034,002	495,717
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	16,492,357	3,457,641
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	801,239,613	64,716,093
110	GENERAL PLANT		
111	389 Land and Land Rights	3,468,083	
112	390 Structures and Improvements	19,527,428	149,595
113	391 Office Furniture and Equipment	7,525,935	260,782
114	392 Transportation Equipment	15,441,850	1,869,809
115	393 Stores Equipment	66,925	
116	394 Tools, Shop, and Garage Equipment	7,346,276	185,408
117	395 Laboratory Equipment	126,158	
118	396 Power Operated Equipment	3,493,545	1,623,431
119	397 Communication Equipment	7,055,046	340,565
120	398 Miscellaneous Equipment	79,679	
121	Subtotal (Enter Total of lines 111 thru 120)	64,130,925	4,429,590
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)	64,130,925	4,429,590
125	TOTAL (Accounts 101 and 106)	922,694,564	79,194,299
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)	922,694,564	79,194,299

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		(1)		22,244,572
87				
88				192,301
89				
90				
91				88,011
92		(1)		23,775,509
93				
94			20,241	2,662,738
95	4,283	1		1,460,862
96	134,983		(23,240)	465,650,883
97				2,097,767
98	123,311			31,749,130
99				
100	238,082	(1)	2,999	228,416,660
101	1,042,244			57,962,781
102	6,086	1	(15,939)	32,866,611
103	355,760	1		10,687,871
104				
105	14,836		15,939	10,530,822
106				
107				
108	32,840	(1)		19,917,157
109	1,952,425	1		864,003,282
110				
111				3,468,083
112				19,677,023
113		1		7,786,718
114	713,495	(1)		16,598,163
115				66,925
116	78,621			7,453,063
117				126,158
118	1,244,052			3,872,924
119	262,788			7,132,823
120				79,679
121	2,298,956			66,261,559
122				
123				
124	2,298,956			66,261,559
125	4,251,381			997,637,482
126				
127				
128				
129	4,251,381			997,637,482

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				
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45	Total			

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				
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45	Total			

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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45	Total			

Construction Work in Progress-Gas (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (Account 107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (less than \$1,000,000) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Hanford DOE	1,617,033	
2	Anacortes lateral upgrade and main replacement	1,132,151	
3			
4			
5			
6			
7			
8	Minor distribution system/general Plant projects each under \$1 million	5,709,620	
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39			
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44			
45	Total	8,458,804	

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				
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36				
	Total			0

Non-Traditional Rate Treatment Afforded New Projects (continued)

6. In column f, list the amount in Account 190, Accumulated Deferred Income Tax; Account 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account 282, Accumulated Deferred Income Taxes – Other Property; Account 283, Accumulated Deferred Income Taxes – Other, associated with the facility.
 7. In column g, report the total amount included in the gas operations expense accounts during the year related to the facility (Account 401, Operation Expense).
 8. In column h, report the total amount included in the gas maintenance expense accounts during the year related to the facility.
 9. In column i, report the amount of depreciation expense accrued on the facility during the year.
 10. In column j, list any other expenses(including taxes) allocated to the facility.
 11. In column k, report the incremental revenues associated with the facility.
 12. Identify the volumes received and used for any incremental project that has a separate fuel rate for that project.
 13. Provide the total amounts for each column.

Line No.	Accumulated Depreciation (e)	Accumulated Deferred Income Taxes (f)	Operating Expense (g)	Maintenance Expense (h)	Depreciation Expense (i)	Other Expenses (including taxes) (j)	Incremental Revenues (k)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Cascade Natural Gas Corporation			
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 Asset Accounting Analyst and approved by the Controller 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 (PowerPlan) 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.

General Description of Construction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.
2. Identify, in a footnote, the specific entity used as the source for the capital structure figures.
3. Indicate, in a footnote, if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ratio (percent) (c)	Cost Rate Percentage (d)
(1)	Average Short-Term Debt	S 7,646,728		
(2)	Short-Term Interest			s 5.92
(3)	Long-Term Debt	D 214,471,000	52.70	d 5.28
(4)	Preferred Stock	P		p
(5)	Common Equity	C 192,552,179	47.30	c 9.44
(6)	Total Capitalization	407,023,179	100.00	
(7)	Average Construction Work In Progress Balance	W 15,464,395		
2. Gross Rate for Borrowed Funds $s(S/W) + d[(D/(D+P+C)) (1-(S/W))]$			4.33	
3. Rate for Other Funds $[1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))]$			2.26	
4. Weighted Average Rate Actually Used for the Year:				
a. Rate for Borrowed Funds -			4.28	
b. Rate for Other Funds -			2.23	

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	(442,537,270)	(442,537,270)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(24,014,067)	(24,014,067)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(1,129,786)	(1,129,786)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(247,688)	(247,688)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(25,391,541)	(25,391,541)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	4,251,381	4,251,381		
13	Cost of Removal	1,261,482	1,261,482		
14	Salvage (Credit)	1,198,144	1,198,144		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	4,314,719	4,314,719		
16	Other Debit or Credit Items (Describe) (footnote details):	312,682	312,682		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(463,301,410)	(463,301,410)		
	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 Terminating and Processing Plant				
27	Transmission	(15,506,121)	(15,506,121)		
28	Distribution	(420,420,037)	(420,420,037)		
29	General	(27,375,252)	(27,375,252)		
30	TOTAL (Total of lines 21 thru 29)	(463,301,410)	(463,301,410)		

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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					126,656	1,705,164		1,831,820
2	Gas Delivered to Storage						1,652,701		1,652,701
3	Gas Withdrawn from						1,127,090		1,127,090
4	Other Debits and Credits					460,873			460,873
5	Balance at End of Year					587,529	2,230,775		2,818,304
6	Dth					199,638	634,073		833,711
7	Amount Per Dth					2.9430	3.5182		3.3804

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)	*	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (c)	Purchases or Additions During the Year (d)
1				
2	Account 124			
3	Oregon weatherization loans			
4	Customer Note Receivable			
5	SERP Plan Assets		10,825,967	713,039
6	SISP Plan Assets		106,865	46,767
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			11,539,006	713,039	
6			153,632	25,567	
7					
8					
9					
10					
11					
12					
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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	None			
2				
3				
4				
5				
6				
7				
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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				
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Name of Respondent

Cascade Natural Gas Corporation

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report
(Mo, Da, Yr)

12/31/2017

Year/Period of Report

End of 2017/Q4

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

PREPAYMENTS (ACCOUNT 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	128,414
2	Prepaid Rents	1,971,399
3	Prepaid Taxes	894,280
4	Prepaid Interest	
5	Miscellaneous Prepayments	311,595
6	TOTAL	3,305,688

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)
 (continued)

EXTRAORDINARY PROPERTY LOSSES (ACCOUNT 182.1)

Line No.	Description of Extraordinary Loss [include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Losses Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
7	None						
8							
9							
10							
11							
12							
13							
14							
15	Total						

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)
(continued)

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (ACCOUNT 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Charges (c)	Costs Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
16	None						
17							
18							
19							
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21							
22							
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24							
25							
26	Total						

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) <input checked="checked" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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Other Regulatory Assets (Account 182.3)

- 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).
- For regulatory assets being amortized, show period of amortization in column (a).
- 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.
- Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
- 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	OR Tax Rate Change	(241,114)	241,114	various			
3							
4	SFAS 109 Regulatory Asset	872,886	(872,886)	various			
5	(OR regulatory asset)						
6							
7	FAS 158 Regulatory Asset	48,995,569	(1,733,163)				47,262,406
8	(Total system asset)						
9							
10	OR MAOP Regulatory Asset		532,792				532,792
11	(OR regulatory asset)						
12							
13							
14							
15							
16							
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40	Total	49,627,341	(1,832,143)		0	0	47,795,198

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	4,106,018	6,781,492	4800-4813	6,337,189	4,550,321
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant	15,841,015	1,718,221	9230	1,273,576	16,285,660
5	Remediation					
6						
7	WA Decoupling Deferral	(92,333)	1,575,337	4800-4813	7,382,267	(5,899,263)
8						
9	WA Decoupling Adjustment		34,071	4800-4813	196,378	(162,307)
10						
11	WA MAOP Deferred Costs	2,219,857	3,847,640	9230	28,803	6,038,694
12						
13	OR Conservation Programs					
14	(amortization period 11/10-present)	(313,394)	6,983,034	4800-4813	10,729,606	(4,059,966)
15				4890		
16	OR Eugene Manufactured Gas Plant					
17	Remediation	1,946,127	51,944	9230	196,505	1,801,566
18						
19	OR Environmental Remediation					
20	Cost Adjustment		164,751	4800-4813	39,095	125,656
21				4890		
22	OR Intervenor Funding					
23	(amortization period 11/10-present)	132,441	107,362	4800-4813	181,162	58,641
24				4890		
25	I/C Asset - Net Benefit Funds	3,555,871	492,966			4,048,837
26						
27	Post Retirement FAS 158	1,321,815	1,952,363	9260	859,705	2,414,473
28						
29	ARO	42,170,920	3,383,044		193,715	45,360,249
30						
31	LOC Commitment Fee		299,217	181	121,492	177,725
32						
33						
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	Total	70,888,337	27,391,442		27,539,493	70,740,286

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[Next page is 234]

Accumulated Deferred Income Taxes (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year	Changes During Year
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric			
3	Gas	26,488,327	15,506,308	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	26,488,327	15,506,308	
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	26,488,327	15,506,308	
8	Classification of TOTAL			
9	Federal Income Tax	25,173,398	15,412,760	
10	State Income Tax	1,314,929	93,548	
11	Local Income Tax			

Accumulated Deferred Income Taxes (Account 190) (continued)

Line No.	Changes During Year	Changes During Year	Adjustments	Adjustments	Adjustments	Adjustments	Balance at End of Year
	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account No. (g)	Debits Amount (h)	Credits Account No. (i)	Credits Amount (j)	
1							
2							
3				(25,603,543)		(20,242,427)	16,343,135
4							
5				(25,603,543)		(20,242,427)	16,343,135
6							
7				(25,603,543)		(20,242,427)	16,343,135
8							
9				(24,515,367)		(19,244,671)	15,031,334
10				(1,088,176)		(997,756)	1,311,801
11							

Capital Stock (Accounts 201 and 204)

1. Report below the details called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common stock - not publicly traded	1,000	1.00	
3				
4				
5				
6				
7				
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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						
4						
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Capital Stock: Subscribed, Liability for Conversion, Premium on, and Installments Received 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	192,553,017
3				
4	Represents excess received over \$1.00 par value			
5	of common stock			
6				
7				
8				
9				
10				
11				
12				
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39				
40	Total		1,000	192,553,017

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		
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40	Total	0

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
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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		
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22		
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26		
27		
28		
TOTAL		

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Securities Issued or Assumed and Securities Refunded or Retired During the Year			

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

None

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	24,431,000
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			214,431,000

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	1,284,049			
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	511,250			
11	4.240	530,000			
12	4.090	511,250			
13	4.240	530,000			
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40		11,142,249			

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	Principal Amount of Debt Issued	Total Expense Premium or Discount	Amortization Period	Amortization Period
	(a)			(b)	(c)
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%	30,000,000	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 - Expired		207,500	07/09/2013	04/24/2017
11	Senior Notes (Series A) 4.09%	12,500,000	62,455	11/24/2014	11/24/2044
12	Senior Notes (Series B) 4.24%	12,500,000	61,105	11/24/2014	11/24/2054
13	Senior Notes (Series C) 4.09%	12,500,000	62,455	01/15/2015	01/15/2045
14	Senior Notes (Series D) 4.24%	12,500,000	61,105	01/15/2015	01/15/2055
15	Revolving Credit Agreement - New		236,967	04/25/2017	04/24/2020
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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	71,891		6,714	65,177
4	61,260		5,035	56,225
5	1,175,676		267,391	908,285
6	57,650		16,176	41,474
7	156,745		7,770	148,975
8	108,013		12,584	95,429
9	116,612		10,067	106,545
10	62,250		62,250	
11	57,945		2,082	55,863
12	57,795		1,528	56,267
13	58,291		2,082	56,209
14	58,050		1,528	56,522
15		236,967	59,241	177,726
16				
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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)	826,242	785,271
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)	12,074,404
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See footnote	(161,231)
6		
7		
8	TOTAL	(161,231)
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	41,626,216
11		
12		
13	TOTAL	41,626,216
14	Income Recorded on Books Not Included in Return	
15	Performance Share Perm	(611,520)
16	AFUDC Equity	(177,923)
17	Interest capitalized adj. (IRS>books)	(59,088)
18	TOTAL	(848,531)
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	(51,078,997)
21		
22		
23		
24		
25		
26	TOTAL	(51,078,997)
27	Federal Tax Net Income	1,611,861
28	Show Computation of Tax:	
29	Rate - 35.00%	
30	Estimated Tax Return Federal Income Tax	564,151
31	Adjustments: (see footnote)	(2,799,695)
32	Provision for Current Federal Income Tax (see footnote)	(2,235,544)
33	Oregon State Tax Calculation (see footnote)	(128,022)
34		
35		

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	120,231	
3	Federal Accrued	1,168,507	
4	Fin 48 - current		
5	Gross Revenue		
6	Washington	407,993	
7	Oregon		
8	Dept of Energy - Oregon		32,624
9	City Franchise & Occupation		
10	Washington	1,330,791	
11	Oregon	734,776	
12	Property		
13	Washington	2,544,524	
14	Oregon		687,135
15	Payroll Taxes	118,694	
16	State Excise - Washington	1,993,376	
17			
18	Miscellaneous		
19			
20			
21			
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39			
TOTAL		8,418,892	719,759

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		(129,101)		1,079
3		(2,234,179)		(1,365)
4				
5				
6		473,581		
7		191,644		
8		81,573		
9				
10		10,168,647		
11		2,742,046		
12				
13		2,678,798		1,106
14		1,458,277		
15		2,221,137		
16		9,000,911		
17				
18		39,380		
19				
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TOTAL		26,692,714		820

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	(128,022)	75,429			83,220
3	(2,235,544)	(1,446,034)		378,997	
4					
5					
6	473,581	410,181		471,393	
7	191,644	191,644			
8	81,573	85,667			36,718
9					
10	10,168,647	9,999,457	8,480	1,508,461	
11	2,742,046	2,740,210	(8,480)	728,132	
12					
13	2,679,904	2,500,856		2,723,572	
14	1,458,277	1,545,484			774,342
15	2,362,089	2,359,984		120,799	
16	9,303,635	9,226,071		2,070,940	
17					
18	39,380	39,380			
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TOTAL	27,137,210	27,728,329		8,002,294	894,280

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					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15				140,952	
16				302,724	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
TOTAL				443,676	

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	Vacation Payable	2,092,666
2	Variable Pay Incentive	1,949,366
3	Wages Payable	1,360,693
4	Accrued 401K Defined Contributions	1,192,988
5	Washington Low Income Assis Liability	679,958
6	SERP Defined Contributions	580,796
7	Energy Trust of Oregon Liability	455,525
8	Oregon Weatherization Liability	398,641
9	Oregon Conservation Achievement Tariff	(403,227)
10	Other Misc Current Liabilities (aggregate)	535,750
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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31		
32		
33		
34		
35		
36		
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39		
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41		
42		
43		
44		
45	Total	8,843,156

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	(318,120)	805.1	47,105,721	35,827,511	(11,596,330)
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	5,627,227	805.1	18,475,976	14,022,767	1,174,018
5	(ammortization period 11/11-present)					
6						
7	SGL Deposit	96,540	134/228.4	24,135		72,405
8	Customer Unclaimed Credits	2,918	131	17,407	15,498	1,009
9	MDUR Interco NC Payable - FAS 158	1,069,661	228.3/182	139,532		930,129
10	Pension Contribution	12,186,712	various	4,169,207	420,872	8,438,377
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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31						
32						
33						
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36						
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38						
39						
40						
41						
42						
43						
44						
45	Total	18,664,938		69,931,978	50,286,648	(980,392)

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	(100,067,346)	(2,341,555)	
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(100,067,346)	(2,341,555)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(100,067,346)	(2,341,555)	
8	Classification of TOTAL			
9	Federal Income Tax	(95,651,640)	(2,184,789)	
10	State Income Tax	(4,415,706)	(156,766)	
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	52,484,094	182.3&254	2,154,130	(52,078,937)
4							
5				52,484,094		2,154,130	(52,078,937)
6							
7				52,484,094		2,154,130	(52,078,937)
8							
9			254	51,472,659	254	2,050,219	(48,413,989)
10			182.3	1,011,435	182.3	103,911	(3,664,948)
11							

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	(36,157,096)	6,713,310	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(36,157,096)	6,713,310	
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru 6)	(36,157,096)	6,713,310	
8	Classification of TOTAL			
9	Federal Income Tax	(34,048,055)	6,983,136	
10	State Income Tax	(2,109,041)	(269,826)	
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			see		see		
3			footnote	35,333,776	footnote	31,268,367	(25,378,377)
4							
5				35,333,776		31,268,367	(25,378,377)
6							
7				35,333,776		31,268,367	(25,378,377)
8							
9				33,975,469		29,972,170	(23,061,620)
10				1,358,307		1,296,197	(2,316,757)
11							

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report End of <u>2017/Q4</u>
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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	2,588,763	282	353,937		49,859,297	52,094,123
2	Oregon Tax Rate Change	(46,149)	282			10,339,489	10,293,340
3	Regulatory Liability - Post Ret FAS 158	1,238,067	186			1,095,890	2,333,957
4							
5							
6							
7							
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41							
42							
43							
44							
45	Total	3,780,681		353,937	0	61,294,676	64,721,420

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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	Revenues for Transition Costs and Take-or-Pay	Revenues for GRI and ACA	Revenues for GRI and ACA
		Amount for Current Year (b)	Amount for Previous Year (c)	Amount for Current Year (d)	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	Other Revenues	Total Operating Revenues	Total Operating Revenues	Dekatherm of Natural Gas	Dekatherm of Natural Gas
	Amount for Current Year (f)	Amount for Previous Year (g)	Amount for Current Year (h)	Amount for Previous Year (i)	Amount for Current Year (j)	Amount for Previous Year (k)
1	160,886,676	148,255,469	160,886,676	148,255,469	17,654,340	15,149,586
2	100,868,460	94,221,079	100,868,460	94,221,079	16,276,810	13,777,345
3						
4						
5						
6						
7						
8	999,833	988,098	999,833	988,098		
9						
10						
11	27,389,122	25,261,174	27,389,122	25,261,174	89,680,849	93,425,359
12						
13						
14						
15						
16	114,496	133,624	114,496	133,624		
17						
18	190,273	152,621	190,273	152,621		
19	290,448,860	269,012,065	290,448,860	269,012,065		
20						
21	290,448,860	269,012,065	290,448,860	269,012,065		

Revenues from Transportation of Gas of Others Through Gathering Facilities (Account 489.1)

1. Report revenues and Dth of gas delivered through gathering facilities by zone of receipt (i.e. state in which gas enters respondent's system).
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.

Line No.	Rate Schedule and Zone of Receipt (a)	Revenues for Transition Costs and Take-or-Pay	Revenues for Transaction Costs and Take-or-Pay	Revenues for GRI and ACA	Revenues for GRI and ACA
		Amount for Current Year (b)	Amount for Previous Year (c)	Amount for Current Year (d)	Amount for Current Year (d)
1	N/A				
2					
3					
4					
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Revenues from Transportation 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	Other Revenues	Total Operating Revenues	Total Operating Revenues	Dekatherm of Natural Gas	Dekatherm of Natural Gas
	Amount for Current Year (f)	Amount for Previous Year (g)	Amount for Current Year (h)	Amount for Previous Year (i)	Amount for Current Year (j)	Amount for Previous Year (k)
1						
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3						
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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	Revenues for Transition Costs and Take-or-Pay	Revenues for GRI and ACA	Revenues for GRI and ACA
		Amount for Current Year (b)	Amount for Previous Year (c)	Amount for Current Year (d)	Amount for Previous Year (e)
1	N/A				
2					
3					
4					
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24					
25					

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	Other Revenues	Total Operating Revenues	Total Operating Revenues	Dekatherm of Natural Gas	Dekatherm of Natural Gas
	Amount for Current Year (f)	Amount for Previous Year (g)	Amount for Current Year (h)	Amount for Previous Year (i)	Amount for Current Year (j)	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	Revenues for Transaction Costs and Take-or-Pay	Revenues for GRI and ACA	Revenues for GRI and ACA
		Amount for Current Year (b)	Amount for Previous Year (c)	Amount for Current Year (d)	Amount for Previous Year (e)
1	N/A				
2					
3					
4					
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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	Other Revenues	Total Operating Revenues	Total Operating Revenues	Dekatherm of Natural Gas	Dekatherm of Natural Gas
	Amount for Current Year (f)	Amount for Previous Year (g)	Amount for Current Year (h)	Amount for Previous Year (i)	Amount for Current Year (j)	Amount for Previous Year (k)
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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	190,273
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
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38		
39		
	Total	190,273

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	Discounted Rate Services	Negotiated Rate Services	Negotiated Rate Services
		Revenue (b)	Volumes (c)	Revenue (d)	Volumes (e)
1	Account 489.1, Revenues from transportation of gas of others through gathering facilities.				
2	Account 489.2, Revenues from transportation of gas of others through transmission facilities.				
3	Account 489.4, Revenues from storing gas of others.				
4	Account 495, Other gas revenues.				
5					
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37					
38					
39					
	Total				

Gas Operation and Maintenance Expenses

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)	0	0
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering	0	0
8	751 Production Maps and Records	0	0
9	752 Gas Well Expenses	0	0
10	753 Field Lines Expenses	0	0
11	754 Field Compressor Station Expenses	0	0
12	755 Field Compressor Station Fuel and Power	0	0
13	756 Field Measuring and Regulating Station Expenses	0	0
14	757 Purification Expenses	0	0
15	758 Gas Well Royalties	0	0
16	759 Other Expenses	0	0
17	760 Rents	0	0
18	TOTAL Operation (Total of lines 7 thru 17)	0	0
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	0
21	762 Maintenance of Structures and Improvements	0	0
22	763 Maintenance of Producing Gas Wells	0	0
23	764 Maintenance of Field Lines	0	0
24	765 Maintenance of Field Compressor Station Equipment	0	0
25	766 Maintenance of Field Measuring and Regulating Station Equipment	0	0
26	767 Maintenance of Purification Equipment	0	0
27	768 Maintenance of Drilling and Cleaning Equipment	0	0
28	769 Maintenance of Other Equipment	0	0
29	TOTAL Maintenance (Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchased for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility-Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Total of lines 33 thru 46)	0	0
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Regulating Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	0	0
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	0
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
70	801 Natural Gas Field Line Purchases	0	0
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
72	803 Natural Gas Transmission Line Purchases	0	0
73	804 Natural Gas City Gate Purchases	164,239,532	139,769,802
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	18,917,115	5,106,494
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	145,322,417	134,663,308
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	3,334,459	4,676,111
87	(Less) 808.2 Gas Delivered to Storage-Credit	4,476,230	4,183,655
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	65,869	38,254
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	65,869	38,254
95	813 Other Gas Supply Expenses	395,472	689,576
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	144,510,249	135,807,086
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	144,510,249	135,807,086
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

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulating Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(less) 845.5 Wharfage Receipts-Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	2,659,197	1,951,637
205	871 Distribution Load Dispatching	455,915	632,872
206	872 Compressor Station Labor and Expenses	97,924	111,564
207	873 Compressor Station Fuel and Power	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses	4,812,466	4,625,388
209	875 Measuring and Regulating Station Expenses-General	747,176	794,942
210	876 Measuring and Regulating Station Expenses-Industrial	184,867	174,094
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,696,009	1,875,765
213	879 Customer Installations Expenses	1,418,415	1,492,616
214	880 Other Expenses	5,400,145	4,549,422
215	881 Rents	160,999	182,434
216	TOTAL Operation (Total of lines 204 thru 215)	17,633,113	16,390,734
217	Maintenance		
218	885 Maintenance Supervision and Engineering	610,964	236,971
219	886 Maintenance of Structures and Improvements	2,579	16,070
220	887 Maintenance of Mains	2,384,129	1,726,516
221	888 Maintenance of Compressor Station Equipment	48,661	44,493
222	889 Maintenance of Measuring and Regulating Station Equipment-General	410,831	357,344
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	28,554	32,497
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	2,042,415	1,553,005
226	893 Maintenance of Meters and House Regulators	1,497,441	1,511,787
227	894 Maintenance of Other Equipment	564,637	207,018
228	TOTAL Maintenance (Total of lines 218 thru 227)	7,590,211	5,685,701
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	25,223,324	22,076,435
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	49,195	(3,325)
233	902 Meter Reading Expenses	732,825	711,524
234	903 Customer Records and Collection Expenses	6,091,369	6,634,133

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	1,228,412	985,349
236	905 Miscellaneous Customer Accounts Expenses	832	1,058
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	8,102,633	8,328,739
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	391,844	880,645
242	909 Informational and Instructional Expenses	31,081	49,989
243	910 Miscellaneous Customer Service and Informational Expenses	68,587	0
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	491,512	930,634
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	4,176	6,975
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	4,176	6,975
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	8,374,821	7,532,035
255	921 Office Supplies and Expenses	3,988,348	3,273,649
256	(Less) 922 Administrative Expenses Transferred-Credit	368,869	382,790
257	923 Outside Services Employed	1,444,583	1,564,701
258	924 Property Insurance	72,012	80,228
259	925 Injuries and Damages	1,357,367	1,492,958
260	926 Employee Pensions and Benefits	6,475,079	6,031,552
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	0
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	39,829	63,766
265	930.2Miscellaneous General Expenses	857,520	1,039,042
266	931 Rents	1,408,634	1,661,945
267	TOTAL Operation (Total of lines 254 thru 266)	23,649,324	22,357,086
268	Maintenance		
269	932 Maintenance of General Plant	54,984	43,941
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	23,704,308	22,401,027
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	202,036,202	189,550,896

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	Gas Received from Others	Gas Delivered to Others	Gas Delivered to Others
		Amount (b)	Dth (c)	Amount (d)	Dth (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	Total	0	0	0	0

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	Natural Gas	Natural Gas	Natural Gas
			Gas Used Dth (c)	Amount of Credit (in dollars) (d)	Amount of Credit (in dollars) (d)	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.)	812	22,823	65,869		
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	Total		22,823	65,869		

Transmission and Compression of Gas by Others (Account 858)

1. Report below details concerning gas transported or compressed for respondent by others equalling more than 1,000,000 Dth and amounts of payments for such services during the year. Minor items (less than 1,000,000) Dth may be grouped. Also, include in column (c) amounts paid as transition costs to an upstream pipeline.
2. In column (a) give name of companies, points of delivery and receipt of gas. Designate points of delivery and receipt so that they can be identified readily on a map of respondent's pipeline system.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Company and Description of Service Performed (a)	* (b)	Amount of Payment (in dollars) (c)	Dth of Gas Delivered (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	Total			

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	363,569
2	Lodging	35,415
3	Training materials	18,510
4	Software Maintenance	15,657
5	Commercial Air Service	14,065
6	Meals & Entertainment	11,379
7	Office Supplies	11,209
8	Vehicle Mileage	3,982
9	Cell Phone	619
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	Total	474,405

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.	248,538
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)	357,889
7	Director's fees (paid to MDU for CNGC's share of director's expenses)	233,017
8	Miscellaneous under \$250,000	18,076
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	Total	857,520

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 group.
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 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				3,032,663
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	418,293			
9	Distribution plant	22,326,129			
10	General plant	1,269,646			
11	Common plant-gas				
12	TOTAL	24,014,068			3,032,663

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 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 depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of provisions and the plant items to which related.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1			3,032,663	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			418,293	Transmission plant
9			22,326,129	Distribution plant
10			1,269,646	General plant
11				Common plant-gas
12			27,046,731	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			

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 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, 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 \$100 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 the debt 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)	299,158
5	Life Insurance (Account 426.2)	
6	Penalties (Account 426.3)	
7	Expenditures for Certain Civic, Political and Related Activities	
8	(Account 426.4)	128,933
9	Other Deductions (Account 426.5)	1,097
10	Total Miscellaneous Income Deductions (Account 426)	429,188
11		
12	(c) Interest on Debt to Associated Companies (Account 430)	
13		
14	(d) Other Interest Expense (Account 431)	
15	Description Interest Rate	
16	Customer Deposits-OR Various	1,654
17	Customer Deposits-WA Various	4,906
18	Deferral Accounts-OR ***	348,135
19	Deferral Accounts-WA FERC Interst Rate	65,412
20	Interest on Short-Term Debt Various	467,753
21	Other Various	
22	Total Other Interest Expense (Account 431)	887,860
23		
24	***Accounts not amortizing-7.284% (Overall rate of return granted in the last	
25	Oregon general rate filing); Accounts amortizing-2.38%	
26		
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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 cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
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22					
23					
24					
25	Total				

Regulatory Commission Expenses (Account 928)

3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA).
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than \$250,000) may be grouped.

Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1							
2							
3							
4							
5							
6							
7							
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9							
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11							
12							
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25							

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	(110,893)
2	Pensions – other	2,645,472
3	Post-retirement benefits other than pensions (PBOP)	149,434
4	Post- employment benefit plans	
5	Other (Specify)	
6	Medical/Dental	3,533,399
7	Various	257,667
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
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25		
26		
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36		
37		
38		
39		
	Total	6,475,079

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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, F 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 a 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. For 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	12,061,883			12,061,883
34	Customer Accounts	4,053,213			4,053,213
35	Customer Service and Informational	52,890			52,890
36	Sales				
37	Administrative and General	6,104,357			6,104,357
38	TOTAL Operation (Total of lines 28 thru 37)	22,272,343			22,272,343
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	4,488,746			4,488,746

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)	4,488,746			4,488,746
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 Terminating and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	16,550,629			16,550,629
56	Customer Accounts (Total of line 34)	4,053,213			4,053,213
57	Customer Service and Informational (Total of line 35)	52,890			52,890
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	6,104,357			6,104,357
60	Total Operation and Maintenance (Total of lines 50 thru 59)	26,761,089			26,761,089
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	26,761,089			26,761,089
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	7,248,717			7,248,717
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	7,248,717			7,248,717
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	488,919			488,919
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	488,919			488,919
75	Other Accounts (Specify) (footnote details)	1,949,366			1,949,366
76	TOTAL Other Accounts	1,949,366			1,949,366
77	TOTAL SALARIES AND WAGES	36,448,091			36,448,091

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 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, 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 according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	Snelson Companies, Inc.	11,894,752
2	Brothers Pipeline Corp.	9,382,729
3	Michels Corporation	7,332,835
4	Northwest Metal Fab & Pipe, Inc.	6,389,702
5	TRC Environmental Corporation	1,920,395
6	Itron, Inc.	1,803,664
7	Infrasource Service, LLC	1,683,810
8	Prosource Technologits, LLC	1,420,180
9	Automotive Rentals, Inc.	1,316,100
10	NC Machinery	1,171,605
11	DAS-CO of Idaho	1,102,901
12	Western States Equipment Company	898,192
13	ABI Service, LLC	846,788
14	Parametricx, Inc.	806,049
15	Tri-Pacific Supply, Inc.	778,767
16	Anchor QEA	643,129
17	Peterson Machinery	641,087
18	Aspect Consulting, LLC	670,019
19	Gas Transmission NW Corp.	475,808
20	Mesa Products, Inc.	454,223
21	Mistras Group, Inc.	385,946
22	Snyder Gas Consluting, LLC	373,574
23	Asphalt Patch Systems, Inc.	347,343
24	JNR Paving, Inc.	316,192
25	Stripe Rite, Inc.	308,346
26	Black & Veatch	289,233
27	Mackay & Sposito, Inc.	285,819
28	Southern Cross Corp.	84,156
29	Heath Consultants, Inc.	276,173
30	Tri-Pacific Supply, Inc.	275,770
31	Jacobs Consultancy, Inc.	255,619
32	Other	10,648,553
33		
34		
35		

Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than \$250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to \$250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2		IGC/MDU/MDU RESOURCES	107	1,075,560
3			426.1	15,234
4			426.2	(315,562)
5			426.4	1,029
6			813	116,821
7			875	104,350
8			880	580,618
9			901	29,131
10			902	183,728
11			903	5,743,496
12			904	13,270
13			909	19,171
14			913	26
15			920	5,241,014
16			921	2,270,703
17			922	(168,391)
18			923	181,630
19			925	112
20	Goods or Services Provided for Affiliated Company			
21			926	36,732
22			930.1	19,583
23			930.2	240,894
24			931	1,349,082
25			Various	1,299,737
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

Compressor Stations

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, products extraction compressor stations, underground 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 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 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		1,350	2,000,731
2	Placed in Service: August 2001			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Compressor Stations

Designate any station that was not operated during the past year. State in a footnote whether the book cost of such station has been retired in the books of account, or if 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 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.

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	9,961		161,853					1
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
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22								
23								
24								
25								

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	

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, 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, is retired in the books of account, or what disposition of the line and its book costs are contemplated.
4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
1	None		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

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 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. This report 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			

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 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 s 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 separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery?
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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27					
28					
29					
30					

Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.

2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.

3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.

4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.

5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.

6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.

7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline 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 to the 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 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 during the reporting year, and (3) contract storage quantities.

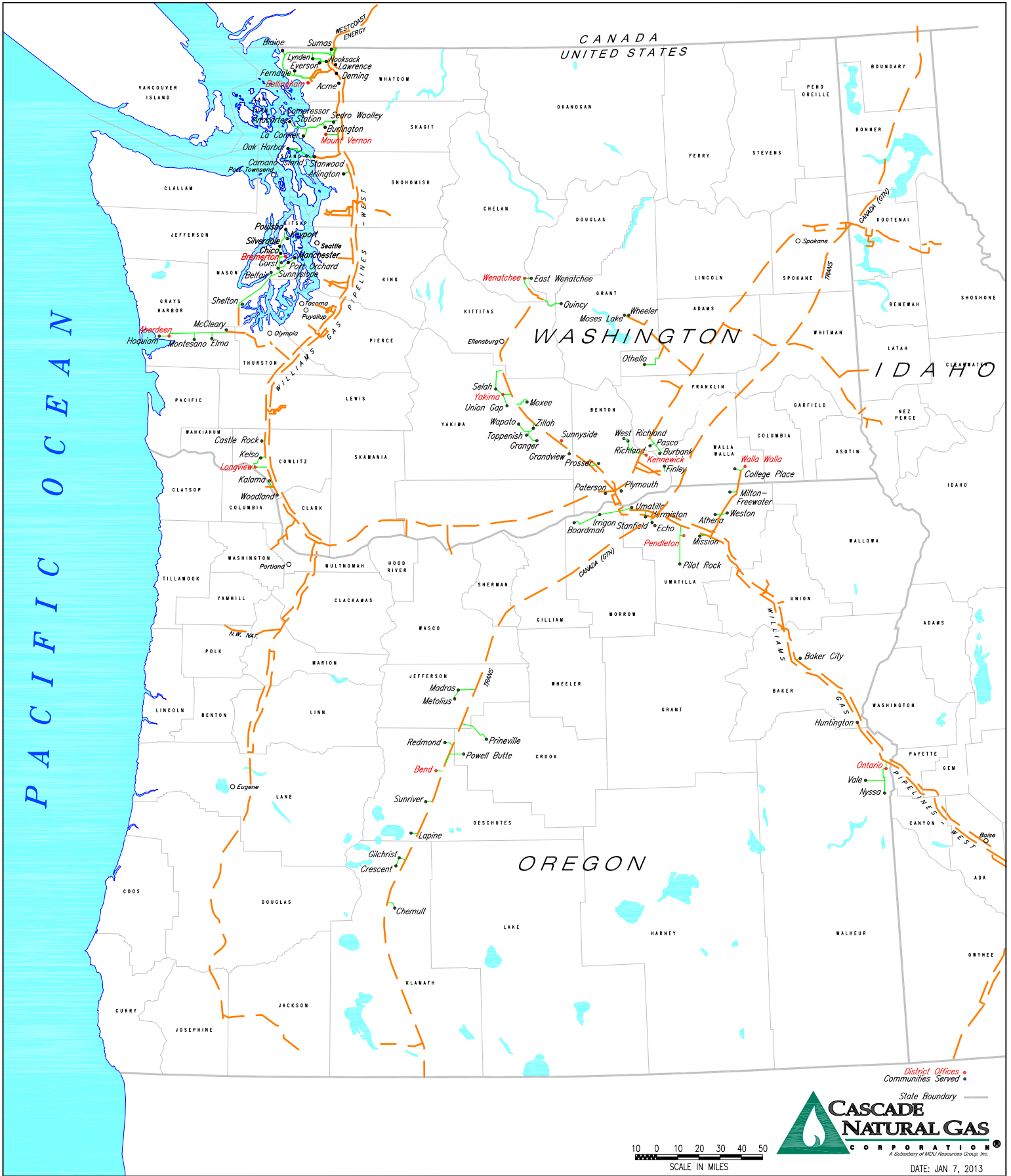
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information in footnotes.

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)		34,816,711	
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)		1,296,598	
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)		89,680,849	
16	Total Receipts (Total of lines 3 thru 15)		125,794,158	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		33,931,150	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	89,680,849	
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)		1,547,691	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		22,823	
30	Total Deliveries (Total of lines 18 thru 29)		125,182,513	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		611,646	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		125,794,159	

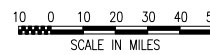
Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Cascade Natural Gas Corporation			
System Maps			

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 than this report. Bind the maps to the report.

See attached map.



District Offices •
Communities Served •



DATE: JAN 7, 2013

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 4 Column: g

Regulatory accounts related to FAS158 and OR rate change adjustments

Schedule Page: 234 Line No.: 4 Column: i

Regulatory accounts related to FAS158 and OR rate change adjustments

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2017	2017/Q4
FOOTNOTE DATA			

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.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 5 Column: a

Customer Advances - 2520.000 to 2520.2991	572,669
CIAC	494,111
Tax Gain (loss) on disposal of assets:	
Pre-1981 assets	(443,298)
Post-1980 assets	(784,713)
Total	(161,231)

Schedule Page: 261 Line No.: 10 Column: a

Tax Expense	8,732,812
Depreciation provision	28,190,594
Vacation Accrual - current year	1,923,846
Bad Debt Expense	1,228,412
SFAS No. 87 accrual-SERP/SISP	753,738
Retiree Medical Accrual	291,067
Prepaid Accrual	209,142
Incentive accrual	166,761
Amort of loss on reacquired debt (4281)	40,971
SFAS No. 87 pension plan accrual	(199,333)
Permanent Diff's:	
50% of business meals & entertainment	159,273
Lobbying (5912.4264)	128,933
Total	41,626,216

Schedule Page: 261 Line No.: 20 Column: a

Depreciation & amortization of plant	(26,547,005)
Deferred Gas Costs	(11,278,210)
MAOP Deferred Costs WA/OR	(4,351,630)
Vacation accrual - prior year	(1,802,092)
Bad debts written off	(1,228,243)
Incentive accrual - prior year	(1,212,601)
Repairs Deduction	(1,074,599)
Section 174 costs	(771,889)
SERP/SISP-perm difference piece	(735,544)
Bremerton & Eugene MGP expenses	(663,163)
SERP-benefit payments out of plan	(603,443)
Prepaid Expenses	(311,595)
Retiree Medical payments	(287,835)
401K Dividends (MDUR)	(155,207)
FAS158 adjustments	(35,420)
Oregon State Income Tax	(21,289)
Royalty Income (15% of receipts)	(1,617)
263A Adjustment - UNICAP	2,385
Total	(51,078,997)

Schedule Page: 261 Line No.: 31 Column: a

Difference between 12/31/16 accrual and tax return	(2,574,088)
Prior year adjustments	(667,189)
Tax Reform	441,582
Total	(2,799,695)

Schedule Page: 261 Line No.: 32 Column: a

Allocated to:	<u>409.1</u>	<u>409.2</u>	<u>Total</u>
---------------	--------------	--------------	--------------

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2017	2017/Q4
FOOTNOTE DATA			

Washington	(1,508,118)	(1,024)	(1,509,142)
Oregon	<u>(726,061)</u>	<u>(341)</u>	<u>(726,402)</u>
Total	(2,234,179)	(1,365)	(2,235,544)

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

Taxable Income for Federal Tax			1,611,861
Oregon adjustments to Federal Taxable Income:			
Oregon State Income Tax expense deducted from Federal Return			21,289
Bonus Depreciation adjustment			<u>(453,611)</u>
Taxable Income for Oregon Tax			1,179,539
Oregon Apportionment Factor			<u>23.7483%</u>
Oregon Taxable Income			280,120
Oregon Tax Rate			<u>7.60%</u>
Estimated Tax Return Oregon Income Tax			21,289
Adjustments:			
Difference between 12/31/16 accrual and tax return			(147,330)
Prior year adjustments			(25,171)
Tax Reform			<u>23,190</u>
Provision for Current Oregon Income Tax			(128,022)
Allocated to:	<u>409.1</u>	<u>409.2</u>	<u>Total</u>
Total	(129,101)	1,079	(128,022)

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: g

Regulatory accounts related to FAS158 and deferred tax effect of OR State Tax Rate increase.

Schedule Page: 276 Line No.: 3 Column: i

Regulatory accounts related to FAS158 and deferred tax effect of OR State Tax Rate increase.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2017	Year/Period of Report 2017/Q4
Cascade Natural Gas Corporation			
FOOTNOTE DATA			

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.

Description (a)	Washington		Oregon	
	Depreciable Plant Base (Thousands) (b)	Composite Rate (Percent) (c)	Depreciable Plant Base (Thousands) (d)	Composite Rate (Percent) (e)
Intangible plant	31,357		12,240	
Manufactured gas production	0		0	
Transmission plant	17,600	1.73%	5,863	1.93%
Distribution plant	660,161	2.59%	183,420	2.85%
General plant	48,465	3.66%	17,057	3.65%
Total -	757,583	2.83%	218,580	3.08%

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	12/31/2017	2017/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 75 Column: a
PTO/Incentive/Severance Pay Liabilities \$1,949,366

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MDU Resources Group, Inc.

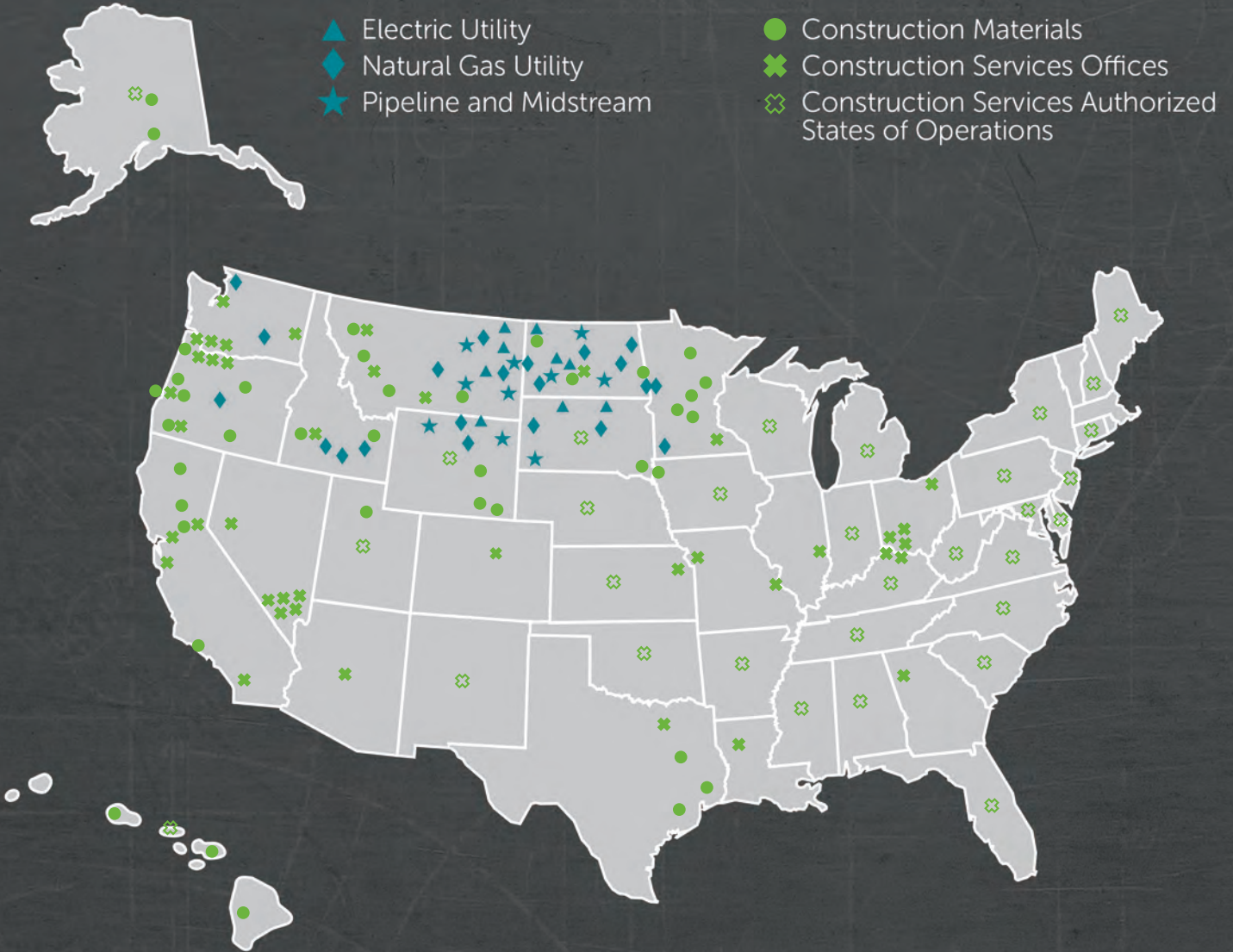
Building a Strong America®

(2017)

Annual Report / Form 10-K / Proxy Statement

(2017)

MDU Resources Group, Inc.



MDU Resources Group, Inc. is a member of the S&P MidCap 400 index and the S&P High-Yield Dividend Aristocrats index. We are Building a Strong America[®] by providing essential products and services through our regulated energy delivery and construction materials and services businesses.

MDU
LISTED
NYSE



10,140
employees

 1.6 Bcf/day

1.1 million



 13th

1 billion



78 cents

Paid dividends
80
consecutive years

Increased dividends
27
consecutive years

• \$284.2 million / \$1.45 EPS ^{from continuing operations}

 **MDU RESOURCES**
GROUP, INC.

Building a Strong America®

Highlights

Years ended December 31,	2017	2016
	(In millions, where applicable)	
Operating revenues	\$4,443.4	\$4,128.8
Operating income	\$ 428.7	\$ 409.1
Earnings on common stock from continuing operations	\$ 284.2	\$ 232.4
Earnings on common stock, including discontinued operations	\$ 280.4	\$ \$63.7
Earnings per common share from continuing operations	\$ 1.45	\$ 1.19
Earnings per common share, including discontinued operations	\$ 1.43	\$.33
Dividends declared per common share	\$.775	\$.755
Weighted average common shares outstanding — diluted	195.7	195.6
Total assets	\$ 6,335	\$ 6,284
Total equity	\$ 2,429	\$ 2,316
Total debt	\$ 1,715	\$ 1,790
Capitalization ratios:		
Total equity	58.6%	56.4%
Total debt	41.4	43.6
	100%	100%
Price/earnings from continuing operations ratio (12 months ended)	18.5x	24.2x
Book value per common share	\$ 12.44	\$ 11.78
Market value as a percent of book value	216.1%	244.2%
Employees	10,140	9,598

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 "2017 Form 10-K." Forward-looking statements are all statements other than statements of historic fact, including without limitation those statements that are identified by the words anticipates, estimates, expects, intends, plans, predicts and similar expressions.

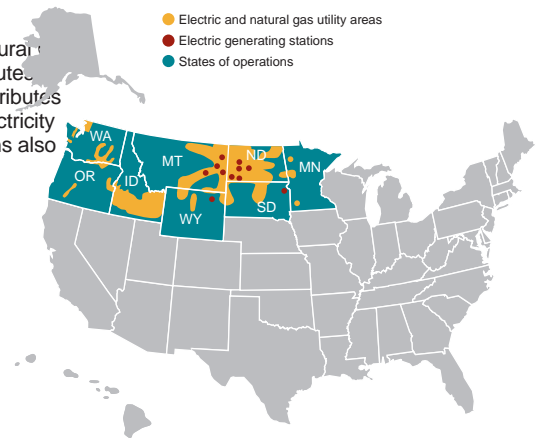
Regulated Energy Delivery

Electric and Natural Gas Utilities

MDU Resources Group's utility companies serve approximately 1.1 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.

2017 Key Statistics

Revenues (millions)	
Electric	\$342.8
Natural gas	\$848.4
Earnings (millions)	
Electric	\$49.4
Natural gas	\$32.2
Electric retail sales (million kWh)	3,306.5
Natural gas distribution (MMdk)	
Sales	112.5
Transportation	144.5

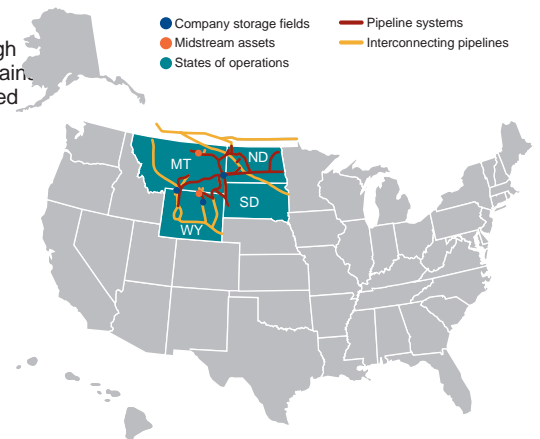


Pipeline and Midstream

WBI Energy provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems 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.

2017 Key Statistics

Revenues (millions)	\$122.2
Earnings (millions)	\$20.5
Pipeline (MMdk)	
Transportation	312.5
Gathering	161



Construction Materials and Services

Construction Materials and Contracting

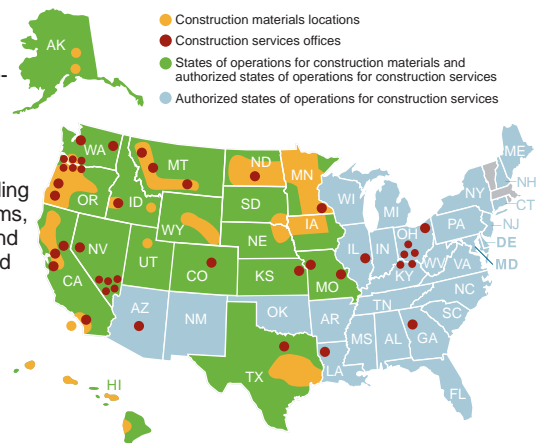
Knife River Corporation mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mix concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services.

Construction Services

MDU Construction Services Group provides inside and outside specialty contracting services, including constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. It also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and supplies.

2017 Key Statistics

Revenues (millions)	
Construction materials	\$1,812.5
Construction services	\$1,367.6
Earnings (millions)	
Construction materials	\$123.4
Construction services	\$53.3
Construction materials sales (thousands)	
Aggregates (tons)	28,213
Asphalt (tons)	6,237
Ready-mix concrete (cubic yards)	3,548
Construction materials aggregate reserves (billion tons)	1.0



Note: The revenues and earnings noted on this page exclude discontinued operations, the Other category and intercompany eliminations.

We are very pleased with our 2017 operating results. The year underscored the strength of our two-pillar strategy, with both our regulated energy delivery businesses and our construction materials and services businesses performing well. We are optimistic about 2018, as well, with a high volume of work in the queue for our construction companies and growth opportunities well underway at our regulated energy companies. We are confident our company will continue to provide the long-term returns you expect from your investment.

Earnings in 2017 from continuing operations were \$284.2 million, or \$1.45 per share, compared to 2016 earnings from continuing operations of \$232.4 million, or \$1.19 per share. Including discontinued operations, MDU Resources reported 2017 earnings of \$280.4 million, or \$1.43 per share, compared to \$63.7 million, or 33 cents per share, in 2016. The company recorded a benefit in the fourth quarter of \$39.5 million, or 20 cents per share, to 2017 earnings attributable to the federal Tax Cuts and Jobs Act, which was signed into law Dec. 22. Absent the benefit from tax reform, our earnings from continuing operations were up 6 cents per share or approximately 5 percent.

This year, we are celebrating our 70th year of being listed on the New York Stock Exchange. Only a handful of companies have been on the exchange as long as ours. We also are listed on Standard & Poor's High-Yield Dividend Aristocrat index. In November, we increased our dividend for the 27th consecutive year, and we have paid dividends uninterrupted for 80 years. Fewer than 100 other U.S.-listed companies have increased their dividend as many consecutive years as MDU Resources.

Utility sees growth in sales, customers

Our electric and natural gas utility business earned \$81.6 million, compared to \$69.3

million in 2016. The 2017 results include a \$6.4 million charge related to an adjustment of net deferred tax assets resulting from tax reform. In 2017, we sold 2 percent more electricity and 13 percent more natural gas than we did in 2016, primarily because our customer base grew 2 percent and our service territories experienced colder weather. Cost recovery through regulatory relief also contributed to the earnings increase.

We recently announced that we will buy the under Spirit Wind farm expansion in southwestern North Dakota. We already own the original 107.5-megawatt under Spirit Wind farm. Construction on the 16-turbine, 48-MW expansion is underway, and we will finalize the estimated \$85 million purchase of these assets when the project is complete at the end of this year. With the addition, our electric generation portfolio will be approximately 27 percent renewables.

We expect our utility customer base of nearly 1.1 million customers to keep growing 1 to 2 percent annually, and we continue our investments in upgrading and expanding our facilities across our system to safely and reliably meet demand. Construction continues through this year on our joint-venture transmission line project, which stretches from Ellendale, North Dakota, to Big Stone City, South Dakota. This Midcontinent Independent System Operator-approved project, expected to be complete in 2019, will help move electricity from renewable generation sources to the MISO market. We also have other growth projects on our system underway that will serve new markets, such as the 21-mile, 12-inch pipeline we expect to complete this year to deliver natural gas to a manufacturing facility and other potential customers in Gwinner, North Dakota.

Based on our customer and demand growth projections, the integrated resource plan we led in 2017 with the North Dakota Public Service Commission

indicates that we expect it will be necessary to develop a large, combined-cycle natural gas-fired electric generation facility around the 2025 timeframe.

Coinciding with investments in our facilities is a significant effort to recover costs through regulatory relief. Rate recovery for our electric utility was approved in every jurisdiction, including by the Federal Energy Regulatory Commission, in 2017. We expect our rate base in the next few years to continue growing 6 percent annually on a compound basis. Our utility operations also must comply with each state regulatory agency in our service territory regarding tax reform's impacts to customers, so it will be a busy year for our regulatory team.

Pipeline business continues organic growth

Our pipeline and midstream business earned \$20.5 million in 2017, compared to \$23.4 million in 2016. The 2017 results include a \$200,000 charge related to an adjustment of net deferred tax assets resulting from tax reform. The decrease in earnings reflects the absence of results from the Pronghorn natural gas processing facility, after selling our interest in the assets at the start of 2017 and receiving approximately \$100 million in proceeds.

While our earnings may have been lower, our pipeline business performed very well. We transported a record volume of natural gas through our system in 2017, up nearly 10 percent over 2016. This was due, in part, to two growth projects that we completed in the second quarter. These projects increased pipeline capacity about 62 million cubic feet per day.

With our pipeline system situated in the heart of the Bakken region, which is producing record volumes of natural gas, we are focused on additional organic growth projects that will help move that gas to market. In 2018, we expect to

complete our 38-mile, 16-inch Valley Expansion project that will connect our existing system near Mapleton, North Dakota, to a third-party pipeline near Felton, Minnesota. We also this year will construct a 13-mile, 24-inch expansion project, which we call Line Section 27, in the heart of the Bakken near Watford City, North Dakota. When these projects are completed, our natural gas transportation capacity will exceed 1.8 billion cubic feet per day.

Additional projects are in the early stages of planning, and we look forward to providing you with more information about those as they progress.

Construction services revenues set record

The construction services business had record revenues in 2017 of \$1.37 billion and earned \$53.3 million, compared to 2016's earnings of \$33.9 million. The 2017 results include a benefit of \$4.3 million from an adjustment to net deferred tax liabilities resulting from tax reform.

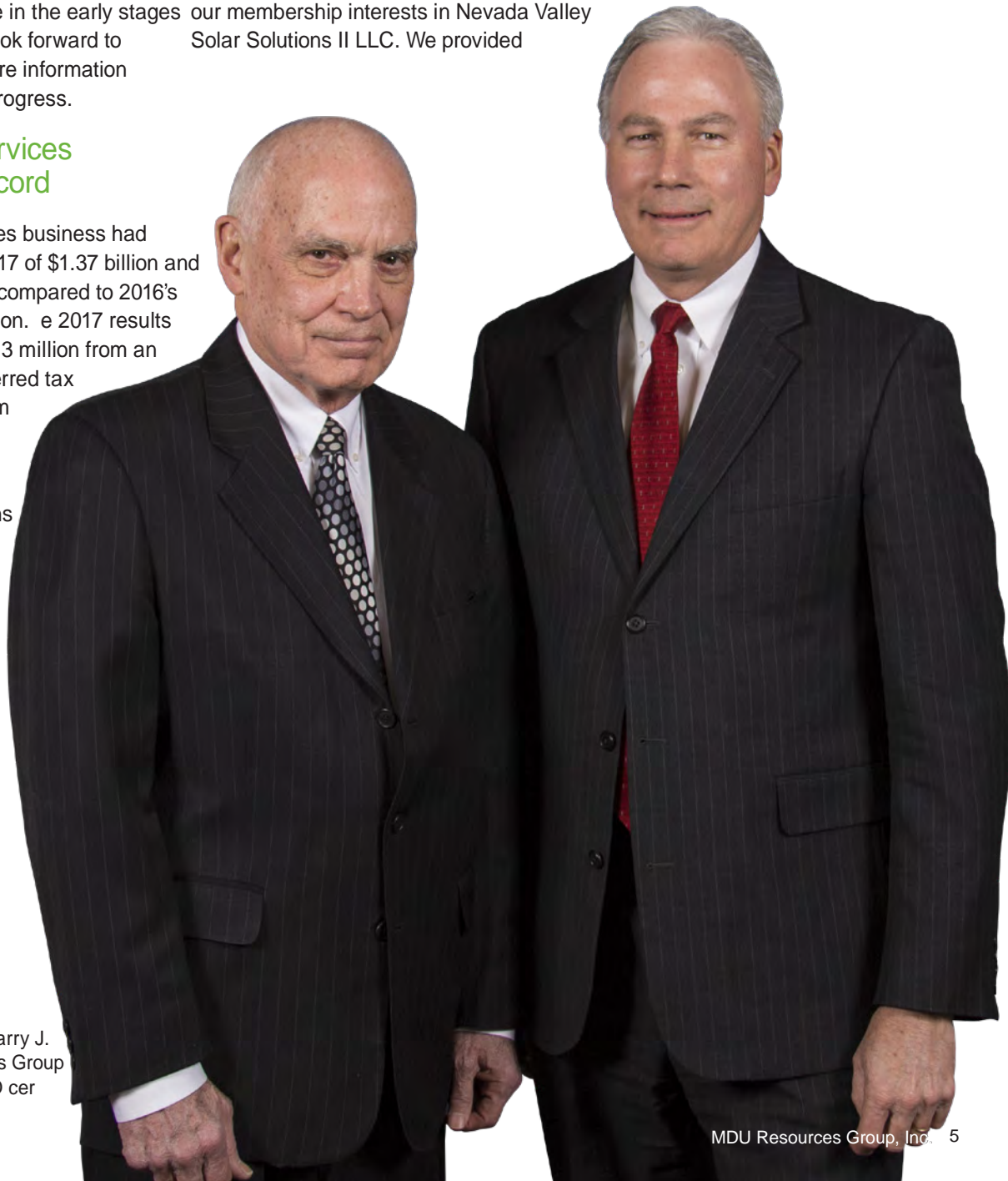
We saw higher workloads and margins in 2017 in both inside specialty electrical contracting work and outside specialty electrical contracting work. Within our inside work, we saw particularly high demand in the high-tech, manufacturing and

retail areas. In outside work, we saw a strong uptick in equipment sales and rentals and engaged in a variety of transmission projects. We also performed storm-recovery work, helping utility companies and their customers who were affected by hurricane activity during the year. Unfortunately, some of our own employees suffered devastating losses as a result of natural disasters this year, and we continue assisting those impacted.

Early in 2017, we announced that we sold our membership interests in Nevada Valley Solar Solutions II LLC. We provided

turnkey engineering, procurement and construction on this 17.5-megawatt community solar project, installing more than 51,400 solar photovoltaic panels on an 80-acre site. Our company is ranked No. 26 on Solar Power World's 2017 Top 500 U.S. Solar Contractors list.

Year-end backlog of \$708 million for this business was up 49 percent compared to 2016. We are the 13th largest specialty contractor in the U.S., according to



MDU Resources Group Chair Harry J. Pearce, left, and MDU Resources Group President and Chief Executive Officer David L. Goodin.

Engineering News Record's 2017 Top 600 Specialty Contractors list, and we have more than 5,000 skilled employees working across 47 states for this business. We are exploring acquisition opportunities in construction services to further grow our market share.

Construction materials has strong growth in 2017

Earnings at our construction materials business were \$123.4 million in 2017, compared to \$102.7 million in 2016. Our 2017 results include a benefit of \$41.9 million from an adjustment to net deferred tax liabilities resulting from tax reform.

Our construction materials operations were impacted early in 2017 by above-average precipitation in nearly every market and natural disasters in some areas.

In fact, precipitation was so heavy in some areas, Knife River Corporation was called on to help complete emergency work, including repairs on the Oroville Dam in California when concerns surfaced over the dam's ability to withstand flooding. A slowdown of construction work in energy-producing states, such as Alaska, North Dakota and Wyoming, also impacted our operations.

Despite the slow start to the year, favorable weather in the fourth quarter allowed our construction materials operations to successfully complete a number of projects, especially in our western markets. We have strong momentum coming into this year, and we are optimistic about the 2018 spring construction bidding season.

Our nearly 1 billion tons of aggregate reserves in growing markets means we are well-positioned to execute on additional

opportunities provided by state and local infrastructure spending initiatives, such as the \$52 billion infrastructure plan approved in California and the \$5.3 billion transportation funding bill passed in Oregon. We are closely following the national conversation on the proposed \$1.5 trillion federal infrastructure package as well and look forward to the projects it would present for both our construction materials and services businesses.

Our construction materials business ended the year with backlog of \$486 million, our third best on record. We are evaluating acquisition opportunities this year for this business to expand our footprint in existing and adjacent markets.

Optimism high going into 2018

We expect 2018 to provide clarity on the impacts the federal Tax Cuts and Jobs Act will have on our company. With regard to our regulated businesses, customers will receive the benefit of the lower income tax rates through the regulatory process. On the construction side of our operations, we anticipate tax reform will result in our customers having more capital to invest in their businesses, which in turn will provide additional project bidding opportunities for

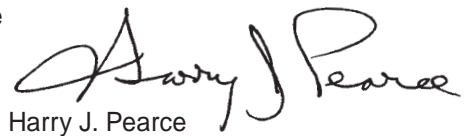
us. We are excited as the mounting momentum we saw through 2017 continues into this year, with no signs of slowing. We have strong prospects for growth at all our companies, with planned capital investment of \$2.3 billion over the next five years, including \$628 million slated for projects this year. Acquisitions will be incremental to this investment. We have the financial flexibility to execute on these projects, as

well, with our strong balance sheet, good liquidity and a BBB+ credit rating with a stable outlook from our rating agencies.

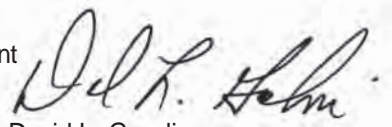
Our employees are a vital component of our growth equation. Our drive and passion for Building a Strong America® helps us successfully provide our customers with the best possible products and services. It is their attention to safety and integrity that makes them the best in the industries in which we operate. It is their concern for their neighbors and each other that make them indispensable in their workplace and their communities.

Our board of directors and management team also play key roles in ensuring our operations are sustainable, by continuing to guide corporate strategy and ensuring diligence in governance, financial, environmental, social and cybersecurity practices. We constantly review the controls we have in place to protect your investment.

We look forward to continuing to provide you with the long-term value you expect from your ownership in MDU Resources, and we thank you for your continued support of our company.



Harry J. Pearce
Chair of the Board



David L. Goodin
President and Chief Executive Officer

February 23, 2018

Board of Directors



Harry J. Pearce

75 (21)
Detroit, Michigan

Chair of MDU Resources Board of Directors

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

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



David L. Goodin

56 (5)
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

68 (23)
Sioux Falls, South Dakota

President and chair of the Everist Co., formerly a construction materials company; a director of several corporations.

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



Karen B. Fagg

64 (13)
Billings, Montana

Retired, formerly vice president of DOWL HKM and formerly chair, 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

65 (5)
Denver, Colorado

Retired, formerly chair, 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

75 (10)
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

68 (17)
Dickinson, North Dakota

Vice Chair of MDU Resources Board of Directors

Chair, 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

75 (5)
Warren, New Jersey

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

Expertise: Multinational business management, corporate governance, technology and cybersecurity.



Patricia L. Moss

64 (15)
Bend, Oregon

Formerly vice chair, president and chief executive officer of Cascade Bancorp and Bank of the Cascades; a director of First Interstate BancSystem Inc.

Expertise: Finance, banking, business development and human resources.



John K. Wilson

63 (15)
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, Chair
Mark A. Hellerstein
A. Bart Holaday
John K. Wilson

Compensation Committee

Thomas Everist, Chair
Karen B. Fagg
William E. McCracken
Patricia L. Moss

Nominating and Governance Committee

Karen B. Fagg, Chair
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, 2017.

Corporate Management



David L. Goodin
56 (35)

President and Chief Executive Officer of MDU Resources

Serves on the company's Board of Directors and as chair 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
62 (32)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River.



Trevor J. Hastings
44 (22)

President and Chief Executive Officer of WBI Holdings, Inc.

Formerly vice president of business development and operations support with Knife River Corporation.



Anne M. Jones
54 (36)

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
44 (23)

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. Kuntz
64 (14)

Vice President, 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.



Peggy A. Link
51 (13)

Vice President and Chief Information Officer of MDU Resources

Formerly assistant vice president of technology and cybersecurity officer of MDU Resources.



Jeffrey S. Thiede
55 (14)

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

Formerly held executive and management positions with MDU Construction Services Group.



Jason L. Vollmer
40 (13)

Vice President, Chief Financial Officer and Treasurer of MDU Resources

Formerly vice president, chief accounting officer and treasurer of MDU Resources.

Stephanie A. Barth, 45 (22)
Vice President, Chief Accounting Officer and Controller of MDU Resources

Dennis L. Haider executive vice president of business development of MDU Resources, retired effective June 12, 2017.

Jason L. Vollmer was named vice president, chief financial officer and treasurer of MDU Resources effective September 30, 2017. He replaced Doran N. Schwartz, who resigned September 29, 2017.

Stephanie A. Barth was named vice president, chief accounting officer and controller of MDU Resources effective September 30, 2017, upon Jason L. Vollmer's promotion to vice president, chief financial officer and treasurer.

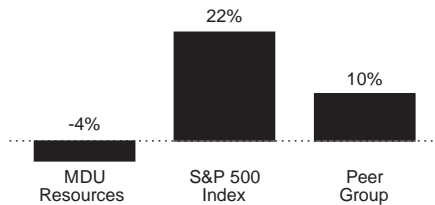
Trevor J. Hastings was named president and chief executive officer of WBI Holdings, Inc. effective October 16, 2017. He replaced Martin A. Fritz, who resigned effective May 23, 2017.

Numbers indicate age and years of service () as of December 31, 2017.

Stockholder Return Comparison

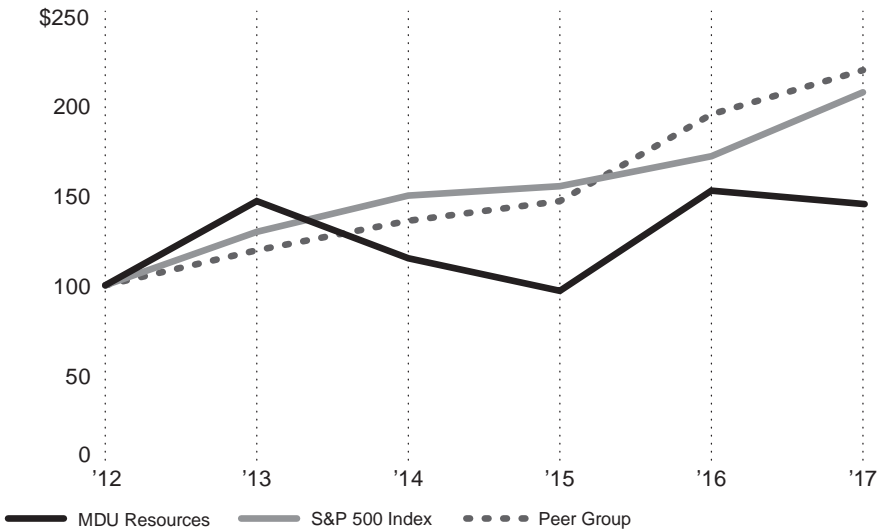
Comparison of One-Year Total Stockholder Return

(as of December 31, 2017)



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

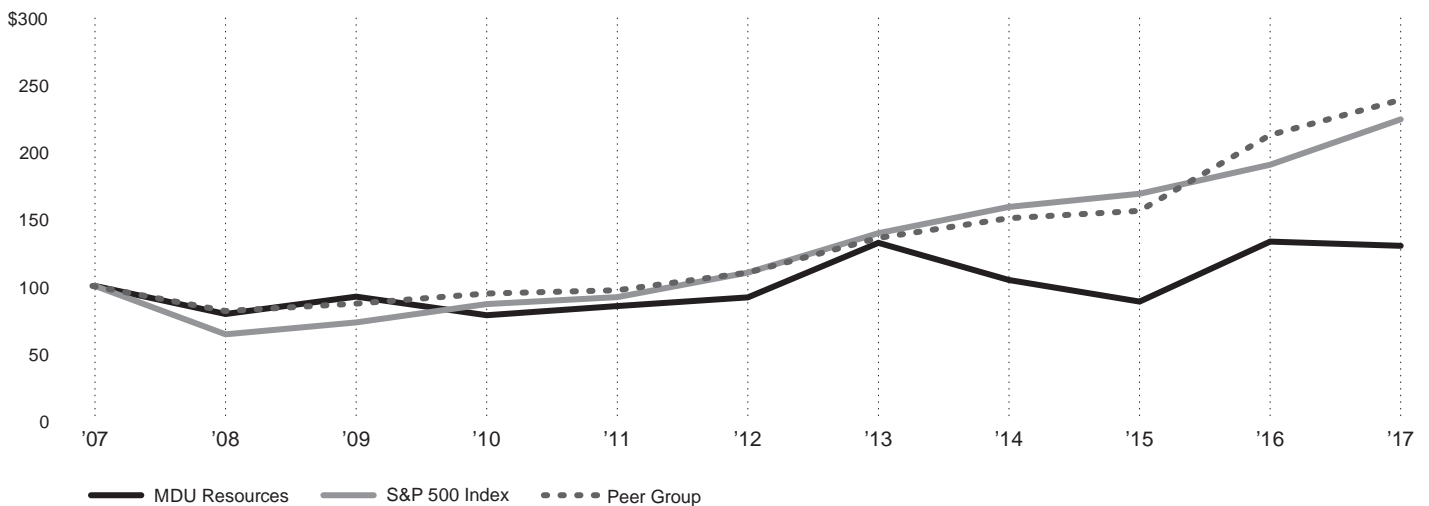
\$100 invested December 31, 2012, in MDU Resources was worth \$146.85 at year-end 2017.



	2012	2013	2014	2015	2016	2017
MDU Resources Group, Inc.	\$100.00	\$147.54	\$116.28	\$94.22	\$152.68	\$146.85
S&P 500 Index	100.00	132.39	150.51	152.59	170.84	208.14
Peer Group	100.00	122.43	139.60	146.50	198.50	219.29

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

\$100 invested December 31, 2007, in MDU Resources was worth \$130.91 at year-end 2017.



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MDU Resources Group, Inc.	\$100.00	\$79.94	\$90.24	\$80.02	\$87.33	\$89.14	\$131.53	\$103.66	\$83.99	\$136.10	\$130.91
S&P 500 Index	100.00	63.00	79.67	91.68	93.61	108.59	143.76	163.44	165.71	185.52	226.03
Peer Group	100.00	82.87	86.90	93.36	96.27	109.18	133.67	152.43	159.96	216.73	239.43

Stockholder Return Comparison

Data is indexed to December 31, 2016, for the one-year total stockholder return comparison, December 31, 2012, for the five-year total stockholder return comparison and December 31, 2007, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer group. 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.

Peer group issuers are ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Avista Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, DACORP, Inc., IES Holdings, Inc., Martin Marietta Materials, Inc., MYR Group Inc., National Fuel Gas Company, Northwest Natural Gas Company, NorthWestern Corporation, Quanta Services, Inc., Sterling Construction Company, Inc., U.S. Concrete, Inc., Vectren Corporation and Vulcan Materials Company.

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, 2017

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 1-03480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

41-0423660
(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:

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Common Stock, par value \$1.00	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act (Check one):

<input checked="" type="checkbox"/> Large accelerated filer	<input type="checkbox"/> Accelerated filer
<input type="checkbox"/> Non-accelerated filer (Do not check if a smaller reporting company)	<input type="checkbox"/> Smaller reporting company
	<input type="checkbox"/> Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2017: \$5,116,974,651.

Indicate the number of shares outstanding of the registrant's common stock, as of February 15, 2018: 195,304,376 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Relevant portions of the registrant's 2018 Proxy Statement, to be filed no later than 120 days from December 31, 2017, are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

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Exhibits

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

Abbreviation or Acronym

AFUDC	Allowance for funds used during construction
Andeavor Field Services LLC	Formerly QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Bcf	Billion cubic feet
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7% ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Capital Electric	Capital Electric Construction Company, Inc., a direct wholly owned subsidiary of MDU Construction Services
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
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
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% 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 previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
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
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
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

Definitions

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
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LWG	Lower Willamette Group
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand dk
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.
MMBtu	Million Btu
MMdk	Million dk
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
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream's 50% ownership interests were sold effective January 1, 2017)
Proxy Statement	Company's 2018 Proxy Statement
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
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	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
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
Thurston County Superior Court	State of Washington Thurston County Superior Court

UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
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., a direct 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% 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 - Business Segment Financial and Operating Data.

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 regulated energy delivery and construction materials and services business, 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.

The Company operates with a two-platform business model. Its regulated energy delivery platform and its construction materials and services platform are each comprised of different operating segments. Some of these segments experience seasonality related to the industries in which they operate. The two-platform approach helps balance this seasonality and the risk associated with each type of industry. Through its regulated energy delivery platform, the Company provides electric and natural gas services to customers, generates, transmits and distributes electricity, and provides natural gas transportation, storage and gathering services. These businesses are regulated by state public service commissions and/or the FERC. The construction materials and services platform provides construction services to a variety of industries, including commercial, industrial and governmental, and provides construction materials through aggregate mining and marketing of related products, such as ready-mix concrete and asphalt.

The Company is organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, and construction services. The Company's reportable segments are determined 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 segments is defined based on the reporting and review process used by the Company's chief executive officer.

Montana-Dakota, Great Plains, Cascade and Intermountain comprise the natural gas distribution segment. Montana-Dakota also comprises the electric segment.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings, Knife River, MDU Construction Services, Centennial Resources and Centennial Capital. WBI Holdings is the pipeline and midstream segment, 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.

On November 21, 2017, the Company announced that its board of directors has directed senior management to explore reorganization to a holding company structure. The purpose of a potential reorganization would be to make Montana-Dakota and Great Plains, which today are

divisions of the Company, into a subsidiary of the holding company, just as the Company's other operating companies are wholly owned subsidiaries.

For more information on the Company's business segments and discontinued operations, see Item 8 - Notes 2 and 13.

As of December 31, 2017, the Company had 10,140 employees with 205 employed at MDU Resources Group, Inc., 963 at Montana-Dakota, 35 at Great Plains, 348 at Cascade, 240 at Intermountain, 319 at WBI Holdings, 3,466 at Knife River and 4,564 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, 2017.

At Montana-Dakota and WBI Energy Transmission, 353 and 68 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, 192 employees are represented by the ICWU. The labor contract with the field operations group is effective through March 31, 2018.

At Intermountain, 127 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2019.

Knife River operates under 43 labor contracts that represent 685 of its construction materials and contracting employees. Knife River is in negotiations on one of its labor contracts.

MDU Construction Services has 130 labor contracts representing the majority of its employees. MDU Construction Services is in negotiations on 10 of its labor contracts.

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, and operations of equipment and fleet vehicles. 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.

Part I

Electric

General Montana-Dakota provides electric service at retail, serving 142,901 residential, commercial, industrial and municipal customers in 178 communities and adjacent rural areas as of December 31, 2017. For more information on the retail customer classes served, see the table below. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 16 electric generating units at 11 facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,200 and 4,900 miles of transmission and distribution lines, respectively, and 73 transmission and 296 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, 2017, Montana-Dakota's net electric plant investment was \$1.4 billion, and rate base was \$1.1 billion.

The retail customers served and respective revenues by class for the electric business were as follows:

	2017		2016		2015	
	Customers Served	Revenues	Customers Served	Revenues	Customers Served	Revenues
	(Dollars in thousands)					
Residential	118,379	\$ 121,171	118,483	\$ 117,014	118,413	\$ 107,767
Commercial	22,764	140,856	22,693	135,390	22,423	121,463
Industrial	242	34,417	244	31,913	240	32,786
Other	1,516	8,275	1,528	7,580	1,511	6,791
	142,901	\$ 304,719	142,948	\$ 291,897	142,587	\$ 268,807

Other electric revenues for Montana-Dakota were \$38.1 million, \$30.4 million and \$11.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The percentage of electric retail revenues by jurisdiction was as follows:

	2017	2016	2015
North Dakota	66%	68%	65%
Montana	20%	19%	21%
Wyoming	9%	8%	9%
South Dakota	5%	5%	5%

Retail electric rates, service, accounting and certain security issuances are subject to regulation by the MTPSC, NDPSC, 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 interconnected 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 interconnected system consists of 15 electric generating units at 10 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 528.2 in 2017. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2017, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 553.1. Montana-Dakota's planning reserve margin requirement within MISO was 530.2 for 2017. 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 2022 will approximate two percent annually. Montana-Dakota's interconnected system electric generating capability includes five steam-turbine generating units at four facilities using coal for fuel, four combustion

turbine units at three facilities, three wind electric generating facilities, two reciprocating internal combustion engines at one facility, a heat recovery electric generating facility and three small portable diesel generators.

In June 2016, Montana-Dakota and a partner began construction on a 345-kilovolt transmission line within the footprint of MISO from Ellendale, North Dakota, to Big Stone City, South Dakota, a distance of about 160 miles, which will facilitate public policy goals and objectives, including delivery of renewable wind energy from North Dakota to eastern markets. The project has been approved as a MISO multivalued project. All necessary easements have been secured and the project is expected to be completed in 2019.

In December 2016, Montana-Dakota signed a 25-year agreement to purchase power from the expansion of the Thunder Spirit Wind farm in southwest North Dakota. In November 2017, the NDPSC approved the advance determination of prudence for the purchase of the Thunder Spirit Wind farm expansion. Montana-Dakota expects to soon have a purchase agreement in place and finalize the purchase when the construction is complete in late 2018. With the addition of the expansion, Montana-Dakota's total wind farm generation capacity will be approximately 155 MW and increase Montana-Dakota's electric generation portfolio to approximately 27 percent renewables. The original 107.5-MW wind farm includes 43 turbines; it was purchased by Montana-Dakota in December 2015. The expansion will include 16 turbines. Acquisition costs for the project are estimated to be approximately \$85 million.

Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2017, Montana-Dakota purchased approximately 26 percent of its net kWh needs for its interconnected system through the MISO market.

Approximately 24 percent of the electricity delivered to customers from Montana-Dakota's owned generation in 2017 was from renewable resources. Although Montana-Dakota's generation resource capacity has increased to serve the needs of customers, the carbon dioxide emission intensity of the electric generation resource fleet has been reduced by more than 25 percent since 2003 and is expected to continue to decline.

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, 2023. Wygen III serves a portion of the needs of its Sheridan-area customers.

Part I

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

Generating Station	Type	Nameplate Rating (kW)	2017 ZRCs (a)	2017 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	83.4	652,071
Heskett	Steam	86,000	87.1	454,134
Heskett	Combustion Turbine	89,038	59.0	3,400
Glen Ullin	Heat Recovery	7,500	4.0	45,548
Cedar Hills	Wind	19,500	5.0	59,385
Diesel Units	Oil	5,475	3.7	9
Thunder Spirit	Wind	107,500	20.6	428,528
South Dakota:				
Big Stone (b)	Steam	94,111	101.8	469,709
Montana:				
Lewis & Clark	Steam	44,000	50.9	225,984
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	16.1	5,453
Glendive	Combustion Turbine	75,522	68.8	2,333
Miles City	Combustion Turbine	23,150	21.5	406
Diamond Willow	Wind	30,000	6.3	93,696
		704,143	528.2	2,440,656
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	189,984
		732,143	528.2	2,630,640

(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.

Virtually all of the current fuel requirements of the Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company under contracts that expire in December 2021 and December 2020, respectively. 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 425,000 to 460,000 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 that expires 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 250,000 tons in 2018 and 2019 from Contura Coal Sales, LLC and 550,000 tons in 2018 from Peabody COALSLES, 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,	2017	2016	2015
Average cost of coal per MMBtu	\$ 2.07	\$ 1.89	\$ 1.75
Average cost of coal per ton	\$ 30.04	\$ 27.45	\$ 25.41

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 2024. 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.

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's results of operations reflect monthly increases or decreases in electric fuel and purchased power costs (including demand charges) and Montana-Dakota 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's results of operations to reflect 90% percent of the increases or decreases in electric 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's results of operations to reflect monthly increases or decreases in electric fuel and purchased power costs. In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota's results of operations to reflect increases or decreases in purchased power costs (including demand charges) 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. Montana-Dakota's results of operations reflect 95% percent of the increases or decreases from the base purchased power costs and in addition also reflects 85% percent of the increases or decreases from the base coal price, which is also recovered through the Electric Power Supply Cost Adjustment. For more information, see Item 8 - Note 4.

For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider, and all of Montana-Dakota's wind resources pertaining to North Dakota electric operations were placed in this rider upon a final order of the most recent North Dakota electric general rate case. Montana-Dakota also has in place in North Dakota a transmission tracker to recover transmission costs associated with MISO and the Southwest Power Pool, regional transmission systems serving Montana-Dakota, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

In South Dakota, Montana-Dakota recovers the South Dakota investment in the Thunder Spirit Wind project through an Infrastructure Rider tracking mechanism that is subject to an annual true-up. Montana-Dakota also has in place in South Dakota a transmission tracker to recover transmission costs associated with MISO and the Southwest Power Pool, regional transmission systems serving Montana-Dakota, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

In Montana, Montana-Dakota recovers in rates through a tracking mechanism the increases associated with its allocated share of Montana state and local taxes assessed to electric operations on an after tax basis.

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, and a final permit was issued in May 2017. An application to modify the Title V Operating Permit for incorporation of two new natural gas-fired engines at Lewis & Clark Station was submitted to the Montana DEQ timely in December 2016, and a final permit was issued in July 2017. The Title V Operating Permit renewal application for Coyote Station was submitted timely to the North Dakota Department of Health in September 2017, with the permit expected to be issued in 2018. 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 2018.

The percentage of the natural gas distribution operations' retail sales revenues by jurisdiction was as follows:

	2017	2016	2015
Idaho	33%	34%	32%
Washington	26%	26%	26%
North Dakota	13%	13%	15%
Montana	9%	8%	8%
Oregon	8%	8%	8%
South Dakota	6%	6%	6%
Minnesota	3%	3%	3%
Wyoming	2%	2%	2%

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 LLC, South Dakota Intrastate Pipeline, TransCanada Corporation, 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 LLC 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-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.

In Montana, Montana-Dakota recovers in rates through a tracking mechanism the increases associated with Montana state and local taxes assessed to natural gas operations on an after tax basis.

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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.

On July 7, 2016, the WUTC approved a full decoupling mechanism where Cascade is allowed recovery of an average revenue per customer regardless of actual consumption. The mechanism also includes an earnings sharing component if Cascade earns beyond its authorized return. The decoupling mechanism will be reviewed following the end of 2019.

On December 22, 2016, the MNPUC approved a request by Great Plains to implement a full revenue decoupling mechanism pilot project. The decoupling mechanism will reflect the period October 1 through September 30 with the first adjustment to be billed to customers effective December 1 each year for the 3 year pilot project.

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 it is 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 2017. Except as to what may be ultimately determined with regard to the issues described in the following paragraph, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2020.

Montana-Dakota and Great Plains have ties to six historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Montana-Dakota is investigating one of these former manufactured gas plant sites and providing input on another site investigation conducted by a third party. To the extent not covered by insurance, Montana-Dakota may seek recovery in its natural gas rates charged to customers for certain investigation and remediation costs incurred for these sites. Cascade has ties to nine historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Cascade is involved in the investigation and remediation of three of these 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 not covered by insurance, Cascade will seek recovery of investigation and remediation costs through 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 natural gas 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, industrial customers, natural gas marketers and others, and serve to enhance system reliability. 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, 2017, its net plant investment was \$404.6 million.

The nonregulated business of this segment owns and operates gathering facilities in Montana and Wyoming. 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 gathering services and a variety of other energy-related services, including cathodic protection and energy efficiency product sales and installation services to large end-users. In November 2016, the Company entered into an agreement to sell its ownership in the Pronghorn assets, which included a 50 percent undivided interest in a natural gas processing plant, both oil and gas gathering pipelines, an oil storage terminal and an oil pipeline in western North Dakota. The transaction closed in January 2017.

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

System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region from both on-system and off-system supply sources. New incremental supply from nontraditional sources have developed, such as the Bakken area in Montana and North Dakota, which has helped offset declines in traditional regional supply sources and supports WBI Energy Transmission's transportation and storage services. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. 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 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, commercial and industrial 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 2017 represented 34 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2022. 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 for existing customers in the fields in which it operates. Its focus on customer service and the variety of services it offers 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 2017 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2020.

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. These products are used in most types of construction, performed by Knife River and other companies, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Knife River focuses on vertical integration of construction services to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. 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.

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Knife River's backlog was approximately \$486 million, \$538 million and \$491 million at December 31, 2017, 2016 and 2015, respectively. The decrease in backlog at December 31, 2017, compared to backlog at December 31, 2016, was primarily attributable to a lower backlog of state agency work. Backlog increases with awards of new contracts and decreases as work is performed on existing contracts. Knife River expects to complete a significant amount of the backlog at December 31, 2017, during the next 12 months.

Knife River's backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved and (c) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a materially adverse effect on backlog. Due to the nature of its contractual arrangements, in many instances Knife River's customers are not committed to the specific volumes of services to be purchased under a contract, but rather Knife River 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.

Competition—Knife River's construction materials products and contracting services are marketed under highly competitive conditions. Price is the principal competitive force to which these products and services are subject, with service, quality, delivery time and proximity to the customer also being significant factors. Knife River focuses on markets located near aggregate sites to reduce transportation costs which allows Knife River to remain competitive with the pricing of aggregate products. 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 and contracting services is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials and contracting services 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 on roads and infrastructure projects, general economic conditions within the market area that influence both the commercial and residential sectors, and prevailing interest rates.

Knife River's customers are a diverse group which includes federal, state and municipal government agencies, commercial and residential developers, and private parties. The mix of sales by customer will vary each year depending on the work available. 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.

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 891 million tons of the 965 million 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 2015 through 2017. 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, 2017, and sales for the years ended December 31, 2017, 2016 and 2015:

Production Area	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
	owned	leased	owned	leased	2017	2016	2015			
Anchorage, AK	,	,	1	,	1,425	1,343	1,837	14,548	N/A	9
Hawaii	,	5	,	,	1,614	1,901	1,892	50,659	2018-2064	28
Northern CA	,	,	9	1	1,785	1,604	1,580	43,812	2018	26
Southern CA	,	2	,	,	55	224	118	91,567	2035	Over 100
Portland, OR	1	3	5	3	4,694	4,044	3,562	213,018	2025-2057	52
Eugene, OR	3	4	6	,	633	662	819	153,975	2021-2049	Over 100
Central OR/WA/ID	,	1	5	2	2,160	1,685	1,493	86,307	2020-2087	49
Southwest OR	5	5	10	6	2,367	2,689	1,872	100,875	2019-2053	44
Central MT	,	,	3	2	1,065	1,135	1,383	28,294	2023-2027	24
Northwest MT	,	,	8	1	1,745	1,514	1,423	64,451	2020	41
Wyoming	,	,	1	2	613	742	888	10,092	2019-2020	13
Central MN	,	1	33	8	2,773	2,831	2,556	50,092	2018-2028	18
Northern MN	2	,	14	2	270	537	595	23,248	2018-2021	50
ND/SD	,	,	2	17	1,100	1,643	1,959	24,389	2019-2028	16
Texas	1	2	1	,	1,192	1,243	1,138	9,709	2022-2029	8
Sales from other sources					4,722	3,783	3,844			
					28,213	27,580	26,959	965,036		

The 965 million tons of estimated aggregate reserves at December 31, 2017, are comprised of 457 million tons that are owned and 508 million tons that are leased. Approximately 45 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 23 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2015 through 2017 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 47 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:

	2017	2016	2015
	(000's of tons)		
Aggregate reserves:			
Beginning of year	989,084	1,022,513	1,061,156
Acquisitions	2,726	24,993	7,406
Sales volumes*	(23,491)	(23,797)	(23,115)
Other**	(3,283)	(34,625)	(22,934)
End of year	965,036	989,084	1,022,513

* 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 the Clean Air Act and the 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

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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 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 2017 and, except as to what may be ultimately determined with regard to the issues described in the following paragraph, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2020.

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.

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 inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This business also designs, constructs and maintains renewable energy projects.

These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2017, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

MDU Construction Services' backlog at December 31 was as follows:

	2017	2016	2015
	(In millions)		
Inside specialty contracting	\$ 625	\$ 435	\$ 408
Outside specialty contracting	83	40	85
	\$ 708	\$ 475	\$ 493

The increase in backlog at December 31, 2017, compared to backlog at December 31, 2016, was primarily attributable to an increase in projects from all revenue streams based on customer demand. Backlog increases with awards of new contracts and decreases as work is performed on existing contracts. MDU Construction Services expects to complete a significant amount of the backlog at December 31, 2017, during the next 12 months.

MDU Construction Services' backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved, (c) pending change orders expected to receive confirmation in the ordinary course of business and (d) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a material adverse effect on backlog. 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.

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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 2017 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2020.

For information regarding construction services litigation, 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. If any of the risks described below actually occur, the Company's business, prospects, financial condition or financial results could be materially harmed.

Economic Risks

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's electric and natural gas transmission and distribution businesses are subject to comprehensive regulation 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, income taxes, property and other taxes, franchises; recovery of purchased power and purchased natural gas costs; and siting of generation and transmission facilities. 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.

There can be no assurance that applicable regulatory commissions will determine all the costs of the Company's electric and natural gas transmission and distribution businesses to have been prudent, which could result in disallowance of costs. Also, the regulatory process for approval of rates for these businesses may not result in full recovery of the costs of providing services. Changes in regulatory requirements or operating conditions may require early retirement of certain assets. While regulation typically provides relief for these types of retirements, there is no assurance the regulators will allow full recovery of all remaining costs leaving stranded asset costs. Rising fuel costs could increase the risk that the utility businesses will not be able to fully recover those fuel costs from their customers.

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, which may defer potential acquirers from approaching the Company or impact the Company's ability to pursue otherwise attractive acquisitions.

Economic volatility affects the Company's operations, as well as the demand for its products and services.

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 affect the funding available for infrastructure spending.

The ability of the Company's electric and natural gas distribution businesses to grow in service territory, customer base and usage demand is affected by the economic environments and population growth 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. Further, any material decreases in energy demand by customers, for economic or other reasons, could have a material adverse impact on the Company's earnings and results of operations.

The Company's operations involve risks that may result from catastrophic events.

The Company's operations include a variety of inherent hazards and operating risks, such as product leaks, explosions, mechanical failures, vandalism, acts of terrorism and acts of war, which could result in loss of human life; personal injury; property damage; environmental pollution; impairment of operations; and substantial financial losses. The Company maintains insurance against some, but not all, of these risks and losses. The occurrence of these losses not fully covered by insurance could have a material effect on the Company's financial position, results of operations and cash flows.

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 cost effective 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's operations, particularly its electric and natural gas transmission and distribution businesses, require significant capital investment. The Company relies on the issuance of long-term debt and equity securities 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 may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- f* A significant economic downturn
- f* The financial distress of unrelated industry leaders in the same line of business
- f* Deterioration in capital market conditions
- f* Turmoil in the financial services industry
- f* Volatility in commodity prices
- f* Terrorist attacks
- f* Cyberattacks

The issuance of a substantial amount of the Company's common stock, whether issued in connection with an acquisition or otherwise, could have a dilutive effect on existing shareholders, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

The regulatory approval, permitting, construction, startup and/or operation of pipelines and power generation and transmission facilities may involve unanticipated events, delays and unrecoverable costs.

The construction, startup and operation of pipelines and power generation and transmission facilities involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to obtain or renew easements; public opposition; 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.

Additionally, operating or other costs required to comply with current pipeline safety regulations and potential new regulations under various agencies could be significant. The regulations require verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of certain lines. Increased emphasis on pipeline safety issues and increased regulatory scrutiny may result in penalties and higher costs of operations. 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.

Financial market changes could impact the Company's pension and post-retirement benefit plans and obligations.

The global demand and price volatility for natural resources, interest rate changes, governmental budget constraints and threat of terrorism can create volatility in the financial markets. Changing financial market conditions could negatively affect the 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 for those plans as well liabilities and funding requirements for multiemployer plans to which the Company is a participating employer.

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The backlogs at the Company's construction materials and contracting and construction services businesses may not accurately represent future revenue.

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. The timing of contract awards, duration of large new contracts and the mix of services can significantly affect backlog. Backlog at any given point in time may not accurately represent the revenue or net income that is realized in any period and the backlog as of the end of the year may not be indicative of the revenue and net income expected to be earned in the following year and should not be relied upon as a stand-alone indicator of future revenues or net income.

The Company's pipeline and midstream business is dependent on factors, including commodity prices and commodity price basis differentials, that are subject to external influences.

Fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; domestic and foreign supplies of oil, NGL and natural gas; political and economic conditions in oil producing countries; actions of the Organization of Petroleum Exporting Countries; and other external factors impact the development of natural gas supplies and the expansion and operation of natural gas pipeline systems. Prolonged depressed prices for oil, NGL and natural gas could negatively affect the growth, results of operations, cash flows and asset values of the Company's pipeline and midstream business.

Reductions in the Company's credit ratings could increase financing costs.

There is no assurance that the Company's current credit ratings, or those of its subsidiaries, will remain in effect or that a rating will not be lowered or withdrawn by a rating agency. The Company's credit ratings may also change as a result of the differing methodologies or changes in the methodologies used by the rating agencies. A downgrade in credit ratings could lead to higher borrowing costs. A credit rating is not a recommendation to buy, sell or hold securities and is applicable only to the specific security to which it applies. Investors should make their own evaluation as to whether an investment in the security is appropriate.

Increasing costs associated with health care plans may adversely affect the Company's results of operations.

The Company's self-insured costs of health care benefits for eligible employees continues to increase. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on operating results, financial position and liquidity. Legislation related to health care could also change the Company's benefit program and costs.

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

If the Company's customers or counterparties experience financial difficulties, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties, particularly customers and counterparties of the Company's construction materials and contracting and construction services businesses for large construction projects, could have a negative impact on the Company's results of operations and cash flows. The Company may also have indirect credit risk due to participation in energy markets such as MISO in which credit losses are socialized to all participants.

Changes in tax law may negatively affect the Company's business.

On December 22, 2017, President Trump signed into law the TCJA that significantly reforms the Internal Revenue Code of 1986, as amended. The TCJA, among other things, includes reductions to United States federal tax rates, repeals the domestic production deduction, disallows regulated utility property for immediate expensing, and modifies or repeals many other business deductions and credits. The changes to the Internal Revenue Code could materially impact the Company. Future guidance, regulations and interpretations clarifying items within the TCJA may be contrary to the Company's current interpretation or regulatory actions and could have an adverse impact to the Company. The Company continues to examine the impact the TCJA may have on the Company in future periods. The TCJA's impact on the economy, including overall demand and competition for the products and services the Company provides and associated labor availability and costs, is unknown and there could be negative impacts to the Company. The Company's utility businesses' cash flows may be negatively impacted by the disallowance of immediate expensing of utility property. Other changes to federal and state tax laws have the ability to benefit or adversely affect the Company's earnings and customer costs. Significant changes to corporate tax rates could result in the impairment of deferred tax assets that are established based on existing law at the time of deferral. Changes to the value of various tax credits could change the economics of resources and the resource selection for the electric generation business. Regulation incorporates

changes in tax law into the rate setting process for the regulated energy delivery businesses and therefore could create timing delays before the impact of changes are realized.

Environmental and Regulatory Risks

The Company's operations could be adversely impacted by climate change.

Climate change may create physical and financial risks to the Company. Such risks could have an adverse effect on the Company's financial condition, results of operations and cash flows.

Utility customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent the largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use by its utility customers due to weather changes may require the Company to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the Company's service territory could also have an impact on revenues. The Company buys and sells electricity that might be generated outside its service territory depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand may raise electricity prices, which would increase the cost of energy provided to customers.

Severe weather impacts the Company's utility service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. Severe weather events may damage or disrupt the Company's electric and natural gas transmission and distribution facilities, which could increase costs to repair damaged facilities and restore service to customers. The cost of providing service could increase to the extent the frequency of extreme weather events increases because of climate change or otherwise. The Company may not recover all costs related to mitigating these physical risks.

Severe weather may result in disruptions to the pipeline and midstream business's natural gas supply and transportation systems. These changes could result in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction.

Extreme weather conditions caused by climate change or otherwise may cause infrastructure construction projects to be delayed or canceled and limit resources available for such projects increasing the project costs at the construction materials and contracting and construction services businesses.

Climate change may impact a region's economic health, which could impact revenues at all of the Company's businesses. The Company's financial performance is tied to the health of the regional economies served. The Company provides natural gas and electric utility service, as well as construction materials and services, for states and communities that are economically affected by the agriculture industry. Increases in severe weather events or significant changes in temperature and precipitation patterns could adversely affect the agriculture industry and correspondingly the economies of the states and communities affected by that industry.

The price of energy also has an impact on the economic health of communities. The cost of additional regulatory requirements to combat climate change, such as regulation of carbon dioxide emissions under the Clean Air Act, or other environmental regulation could impact the availability of goods and prices charged by suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect the Company's ability to access capital markets or cause less than ideal terms and conditions.

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, regarding air and 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 and natural gas gathering, transmission and storage operations. These laws and regulations generally require the Company to obtain and comply with a 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.

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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 rule, under the RCRA, for coal combustion residuals that regulates coal ash as a solid waste and not a hazardous waste. Site and groundwater analyses as required by the rule may identify the need to upgrade or close 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 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 at this facility 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. 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 76 percent of the electricity it generated in 2017 was from coal-fired facilities.

On October 23, 2015, the EPA published the Clean Power Plan rule that requires existing fossil fuel-fired electric generating facilities to reduce carbon dioxide emissions. On February 9, 2016, however, 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 EPA filed a motion with the D.C. Circuit Court on March 28, 2017, requesting the Clean Power Plan's case be held in abeyance. The D.C. Circuit Court granted the EPA's motion to hold the case in abeyance for 60 days. On August 8, 2017, the D.C. Circuit Court issued an order holding the case in abeyance for an additional 60-day period and directed the EPA to file status reports at 30-day intervals. In parallel, the EPA published a proposal on October 16, 2017, to repeal the Clean Power Plan in its entirety and followed with an advance notice of proposed rulemaking published in the Federal Register on December 28, 2017, requesting comment on replacing the Clean Power Plan through new rulemaking. Compliance costs will become clearer as the EPA completes new rulemaking.

On January 14, 2015, the federal government of the United States announced a goal to reduce methane emissions from the oil and natural gas industry by 40 percent to 45 percent below 2012 levels by 2025. On June 3, 2016, the EPA published a rule updating new source performance standards for the oil and natural gas industry. The rule builds on 2012 requirements to reduce volatile organic compound emissions from oil and natural gas sources by establishing requirements to reduce methane emissions from previously regulated sources, as well as adding volatile organic compound and methane requirements for sources previously not covered by the rule. The rule impacts new and modified natural gas gathering and boosting stations and transmission and storage compressor stations. WBI Energy is currently complying with the rules impacting new and modified sources. In addition, on March 10, 2016, the EPA announced plans to reduce emissions from the oil and natural gas industry by moving to regulate emissions from existing sources. On November 10, 2016, the EPA issued an Information Collection Request to oil and gas facility operators, including WBI Energy, to begin the process of existing source rule development. On March 7, 2017, the EPA published notice of withdrawal of the Information Collection Request.

On September 15, 2016, the Washington DOE issued a Clean Air rule that requires carbon dioxide emission reductions from various industries in the state, including emissions from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. 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 are reduced by an additional 1.7 percent of the baseline from the previous year's emissions. Compliance for natural gas suppliers is to be achieved through purchasing emissions credits from projects located within the state of Washington and, to a limited and declining extent, out-of-state allowances. Purchasing emissions credits and allowances will increase operating costs for Cascade. If Cascade is not able to receive timely and full recovery of compliance costs from its customers, such costs could adversely impact the results of its operations. On September 27, 2016 and September 30, 2016, Cascade

and three other natural gas distribution utility companies jointly filed complaints in the United States District Court for the Eastern District of Washington and the Thurston County Superior Court, respectively, asking the courts to deem the rule invalid. The companies asserted that the Washington DOE undertook this rulemaking without the requisite statutory authority. On December 15, 2017, the Thurston County Superior Court vacated the Clean Air rule holding that it is invalid due to a lack of legislative approval to adopt the rule. The ruling may still be appealed by the Washington DOE or interveners. Litigation in the United States District Court for the Eastern District of Washington remains in abeyance pending evaluation of the recent ruling in the Thurston County Superior Court.

Additional treaties, legislation or regulations to reduce GHG emissions may be adopted that affect the Company's 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 or reduce demand for the Company's utility services. If the Company's utility operations do not receive timely and full recovery of GHG emission compliance costs from customers, then such costs could adversely impact the results of its operations and cash flows.

The Company monitors, analyzes and reports GHG emissions from its other operations as required by applicable laws and regulations. The Company will continue to monitor GHG regulations and their potential impact on 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.

Other Risks

The Company's various businesses are seasonal and subject to weather conditions that can adversely affect the Company's operations, 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 and affect the price of energy commodities. Utility operations have historically generated lower revenues when weather conditions are cooler than normal in the summer and warmer than normal in the winter particularly in jurisdictions that do not have decoupling mechanisms in place. Where decoupling mechanisms are in place, there is no assurance the Company will continue to receive such regulatory protection from adverse weather in future rates.

Adverse weather conditions, such as heavy or sustained rainfall or snowfall, storms, wind, and colder weather may affect the demand for products and the ability to perform services at the construction businesses and affect ongoing operation and maintenance and construction activities for the electric and natural gas transmission and distribution 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.

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 experience 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 for gathering, transportation and storage business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company's inability to obtain, develop and retain key personnel and skilled labor forces may have a negative effect on the Company's operations.

The Company must attract, develop and retain executive officers and other professional, technical and skilled labor forces with the skills and experience necessary to successfully manage, operate and grow the Company's businesses. Competition for these employees is high, and in some cases competition for these employees is on a regional or national basis. A shortage in the supply of these skilled personnel creates competitive hiring markets and increased labor expenses, decreased productivity and potentially lost business opportunities. Additionally, if the Company is unable to hire employees with the requisite skills, the Company may also be forced to incur significant training expenses. As a result, the Company's ability to maintain productivity, relationships with customers, competitive costs, and quality services is limited by the ability to employ the necessary skilled personnel and could negatively affect the Company's results of operations, financial position and cash flows.

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The Company's construction materials and contracting and construction services businesses may be exposed to warranty claims.

The Company, particularly its construction businesses, may provide warranties guaranteeing the work performed against defects in workmanship and material. If warranty claims occur, they may require the Company to re-perform the services or to repair or replace the warranted item, at a cost to the Company, and could also result in other damages if the Company is not able to adequately satisfy warranty obligations. In addition, the Company may be required under contractual arrangements with customers to warrant any defects or failures in materials the Company purchased from third parties. While the Company generally requires suppliers to provide warranties that are consistent with those the Company provides to customers, if any of the suppliers default on their warranty obligations to the Company, the Company may nonetheless incur costs to repair or replace the defective materials. Costs incurred as a result of warranty claims could adversely affect the Company's results of operations, financial condition 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 restrict or influence the Company's ability or decision to pay dividends on its common stock and adversely affect the Company's stock price.

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

Various operating subsidiaries of the Company participate in approximately 75€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 35€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 if the other participating employers in such plans withdraw from the plans and are not able to contribute amounts sufficient to fund the unfunded liabilities associated with their participation 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 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. The Company could also incur additional withdrawal liability if its withdrawal from a plan is determined by that plan to be part of a mass withdrawal.

Information technology disruptions or cyberattacks could adversely impact the Company's operations.

The Company's operations require uninterrupted operation of information technology systems and network infrastructure. While the Company has policies, procedures and processes in place designed to strengthen and protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, theft, sabotage, malicious software, acts of terrorism, acts of war, acts of nature or other causes. If these systems fail or become comprised, and they are not recovered in a timely manner, the Company may be unable to fulfill critical business functions. This may include interruption of electric generation, transmission and distribution facilities, natural gas storage and pipeline facilities, and facilities for delivery of construction materials or other products and services. The Company's accounting systems and its ability to collect information and invoice customers for products and services could also be disrupted. If the Company's operations were disrupted, it could result in decreased revenues or significant remediation costs that have a material adverse effect on the Company's results of operations and cash flows. Additionally, because electric generation and transmission systems and natural gas pipelines are part of interconnected systems with other operators' facilities, a cyber-related disruption in another operator's system could negatively impact the Company's business.

The Company, through the ordinary course of business, requires access to sensitive customer, employee and Company data. While the Company has implemented extensive security measures, a breach of its systems could compromise sensitive data. Such an event could result in negative publicity and reputational harm, remediation costs, legal claims and fines that could have an adverse effect on the Company's financial results. Third-party service providers that perform critical business functions for the Company or have access to sensitive information within the Company also may be vulnerable to security breaches and information technology risks that could have an adverse effect on the Company.

The Company may be subject to potential material liabilities relating to the past sale of assets or businesses, primarily arising from events prior to sale.

The Company previously sold its oil and natural gas assets and its membership interests in Dakota Prairie Refining. The Company may be subject to potential liabilities, either directly or through indemnification of the buyers or others, relating to these transactions or other sales, primarily arising from events prior to the sale, or from breaches of any representations, warranties or covenants in the purchase and sale agreements.

Other factors that could impact the Company's businesses.

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

- f* Acquisition, disposal and impairments of assets or facilities
- f* Changes in operation, performance and construction of plant facilities or other assets
- f* Changes in present or prospective generation
- f* The availability of economic expansion or development opportunities
- f* Population growth rates and demographic patterns
- f* Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- f* The cyclical nature of large construction projects at certain operations
- f* Unanticipated project delays or changes in project costs, including related energy costs
- f* Unanticipated changes in operating expenses or capital expenditures
- f* Labor negotiations or disputes
- f* Inability of the contract counterparties to meet their contractual obligations
- f* Changes in accounting principles and/or the application of such principles to the Company
- f* Changes in technology
- f* Changes in legal or regulatory proceedings
- f* Losses or costs relating to litigation
- f* The ability to effectively integrate the operations and the internal controls of acquired companies

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings required by this item, 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 New York Stock Exchange during 2017 and 2016 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2017			
First quarter	\$29.74	\$25.83	\$.1925
Second quarter	27.89	25.58	.1925
Third quarter	27.73	25.14	.1925
Fourth quarter	28.22	25.89	.1975
			\$.7750
2016			
First quarter	\$19.55	\$15.57	\$.1875
Second quarter	24.01	18.70	.1875
Third quarter	25.79	22.47	.1875
Fourth quarter	29.92	24.49	.1925
			\$.7550

As of December 31, 2017, the Company's common stock was held by approximately 11,703 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 9.

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, 2017	,	,	,	,
November 1 through November 30, 2017	38,121	\$26.88	,	,
December 1 through December 31, 2017	2,451	\$27.70	,	,
Total	40,572			

(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

	2017	2016	2015	2014	2013	2012
Selected Financial Data						
Operating revenues (000's):						
Electric	\$ 342,805	\$ 322,356	\$ 280,615	\$ 277,874	\$ 257,260	\$ 236,895
Natural gas distribution	848,388	766,115	817,419	921,986	851,945	754,848
Pipeline and midstream	122,213	141,602	154,904	157,292	144,568	142,610
Construction materials and contracting	1,812,529	1,874,270	1,904,282	1,765,330	1,712,137	1,617,425
Construction services	1,367,602	1,073,272	926,427	1,119,529	1,039,839	938,558
Other	7,874	8,643	9,191	9,364	9,620	10,370
Intersegment eliminations	(58,060)	(57,430)	(78,786)	(136,302)	(95,201)	(74,595)
	\$ 4,443,351	\$ 4,128,828	\$ 4,014,052	\$ 4,115,073	\$ 3,920,168	\$ 3,626,111
Operating income (loss) (000's):						
Electric	\$ 82,153	\$ 68,497	\$ 57,955	\$ 61,331	\$ 54,274	\$ 49,852
Natural gas distribution	84,878	65,014	53,810	65,633	78,829	67,579
Pipeline and midstream	36,924	43,374	29,988	46,713	20,896	49,139
Construction materials and contracting	143,716	178,719	146,026	86,462	93,629	57,864
Construction services	81,590	53,705	43,376	82,309	85,246	66,531
Other	(549)	(189)	(8,438)	(5,366)	(4,384)	(5,325)
Intersegment eliminations	•	,	(2,942)	(9,900)	(7,176)	,
	\$ 428,712	\$ 409,120	\$ 319,775	\$ 327,182	\$ 321,314	\$ 285,640
Earnings (loss) on common stock (000's):						
Electric	\$ 49,366	\$ 42,222	\$ 35,914	\$ 36,731	\$ 34,837	\$ 30,634
Natural gas distribution	32,225	27,102	23,607	30,484	37,656	29,409
Pipeline and midstream	20,493	23,435	13,250	24,666	7,701	26,588
Construction materials and contracting	123,398	102,687	89,096	51,510	50,946	32,420
Construction services	53,306	33,945	23,762	54,432	52,213	38,429
Other	(1,422)	(3,231)	(14,941)	(7,386)	(10,776)	(7,209)
Intersegment eliminations	6,849	6,251	5,016	(6,095)	(4,307)	,
Earnings on common stock before income (loss) from discontinued operations	284,215	232,411	175,704	184,342	168,270	150,271
Income (loss) from discontinued operations, net of tax*	(3,783)	(300,354)	(834,080)	109,311	109,615	(151,710)
Loss from discontinued operations attributable to noncontrolling interest	•	(131,691)	(35,256)	(3,895)	(363)	,
	\$ 280,432	\$ 63,748	\$ (623,120)	\$ 297,548	\$ 278,248	\$ (1,439)
Earnings (loss) per common share before discontinued operations - diluted						
	\$ 1.45	\$ 1.19	\$.90	\$.96	\$.89	\$.80
Discontinued operations attributable to the Company, net of tax						
	(.02)	(.86)	(4.10)	.59	.58	(.81)
	\$ 1.43	\$.33	\$ (3.20)	\$ 1.55	\$ 1.47	\$ (.01)
Common Stock Statistics						
Weighted average common shares outstanding€-diluted (000's)						
	195,687	195,618	194,986	192,587	189,693	188,826
Dividends declared per common share	\$.7750	\$.7550	\$.7350	\$.7150	\$.6950	\$.6750
Book value per common share	\$ 12.44	\$ 11.78	\$ 12.83	\$ 16.66	\$ 15.01	\$ 13.95
Market price per common share (year end)	\$ 26.88	\$ 28.77	\$ 18.32	\$ 23.50	\$ 30.55	\$ 21.24
Market price ratios:						
Dividend payout**	53%	63%	82%	74%	78%	84%
Yield	2.9%	2.7%	4.1%	3.1%	2.3%	3.2%
Market value as a percent of book value	216.1%	244.2%	142.8%	141.1%	203.5%	152.3%

* 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 \$157.8 million (after tax) and \$475.4€million (after tax) in 2016 and 2015, respectively.

** Based on continuing operations.

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Item 6. Selected Financial Data (continued)

	2017	2016	2015	2014	2013	2012
General						
Total assets (000's)	\$ 6,334,666	\$ 6,284,467	\$ 6,565,154	\$ 7,805,405	\$ 7,043,365	\$ 6,675,609
Total long-term debt (000's)	\$ 1,714,853	\$ 1,790,159	\$ 1,796,163	\$ 2,016,198	\$ 1,773,050	\$ 1,738,833
Capitalization ratios:						
Total equity	59%	56%	58%	62%	62%	60%
Total debt	41	44	42	38	38	40
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	3,306,470	3,258,537	3,316,017	3,308,358	3,173,086	2,996,528
Electric system summer and firm purchase contract ZRCs (Interconnected system)	553.1	559.7	547.3	584.0	583.5	552.8
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	530.2	559.7	547.3	522.4	508.3	550.7
All-time demand peak - kW (Interconnected system)	611,542	611,542	611,542	582,083	573,587	573,587
Electricity produced (thousand kWh)	2,630,640	2,626,763	1,898,160	2,519,938	2,430,001	2,299,686
Electricity purchased (thousand kWh)	955,687	904,702	1,658,002	1,010,422	971,261	870,516
Average cost of electric fuel and purchased power per kWh	\$.022	\$.021	\$.024	\$.025	\$.025	\$.023
Natural Gas Distribution						
Sales (Mdk)	112,551	99,296	95,559	104,297	108,260	93,810
Transportation (Mdk)	144,477	147,592	154,225	145,941	149,490	132,010
Degree days (% of normal)						
Montana-Dakota/Great Plains	100%	89%	88%	103%	105%	84%
Cascade	107%	87%	83%	89%	98%	96%
Intermountain	111%	96%	89%	95%	110%	91%
Pipeline and Midstream						
Transportation (Mdk)	312,520	285,254	290,494	233,483	178,598	137,720
Gathering (Mdk)	16,064	20,049	33,441	38,372	40,737	47,084
Customer natural gas storage balance (Mdk)	22,397	26,403	16,600	14,885	26,693	43,731
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	28,213	27,580	26,959	25,827	24,713	23,285
Asphalt (tons)	6,237	7,203	6,705	6,070	6,228	5,988
Ready-mixed concrete (cubic yards)	3,548	3,655	3,592	3,460	3,223	3,157
Aggregate reserves (000's tons)	965,036	989,084	1,022,513	1,061,156	1,083,376	1,088,236

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

The Company's strategy is to apply its expertise in the regulated energy delivery and construction materials and services businesses to increase market share, increase profitability and enhance shareholder value through organic growth opportunities and strategic acquisitions. The Company is focused on a disciplined approach to the acquisition of well-managed companies and properties.

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

On December 22, 2017, President Trump signed into law the TCJA making significant changes to the United States federal income tax laws. Some of the more material changes from the TCJA impacting the Company includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. During the fourth quarter of 2017, the Company performed a one-time revaluation of the net deferred tax liabilities to account for the reduction in the corporate tax rate from 35 percent to 21 percent, as discussed in Item 8 - Note 11. The Company is currently reviewing the components of the TCJA and evaluating the impact on the Company for 2018 and thereafter. For information pertinent to the specific impacts or trends identified by the Company's business segments, see Business Segment Financial and Operating Data.

Consolidated Earnings Overview

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

Years ended December 31,	2017	2016	2015
	(In millions, except per share amounts)		
Electric	\$ 49.4	\$ 42.2	\$ 35.9
Natural gas distribution	32.2	27.1	23.6
Pipeline and midstream	20.5	23.4	13.3
Construction materials and contracting	123.4	102.7	89.1
Construction services	53.3	33.9	23.8
Other	(1.5)	(3.2)	(15.0)
Intersegment eliminations	6.9	6.3	5.0
Earnings before discontinued operations	284.2	232.4	175.7
Loss from discontinued operations, net of tax	(3.8)	(300.4)	(834.1)
Loss from discontinued operations attributable to noncontrolling interest	•	(131.7)	(35.3)
Earnings (loss) on common stock	\$ 280.4	\$ 63.7	\$ (623.1)
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	\$ 1.46	\$ 1.19	\$.90
Discontinued operations attributable to the Company, net of tax	(.02)	(.86)	(4.10)
Earnings (loss) per common share - basic	\$ 1.44	\$.33	\$ (3.20)
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	\$ 1.45	\$ 1.19	\$.90
Discontinued operations attributable to the Company, net of tax	(.02)	(.86)	(4.10)
Earnings (loss) per common share - diluted	\$ 1.43	\$.33	\$ (3.20)

2017 compared to 2016 The Company recognized consolidated earnings of \$280.4 million in 2017, compared to consolidated earnings of \$63.7 million in 2016. This increase was the result of:

- f Discontinued operations which reflect the absence in 2017 of a loss associated with the sale of the refining business in June 2016
- f An income tax benefit of \$39.5 million primarily for the revaluation of the Company's net deferred tax liabilities, as discussed in Item 8 - Note 11
- f Higher inside and outside specialty contracting margins at the construction services business
- f Higher natural gas retail sales margins at the natural gas distribution business
- f Higher electric retail sales margins at the electric business

These increases were partially offset by:

- f Lower asphalt product margins and lower construction margins at the construction materials and contracting business

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f Lower gathering and processing revenues at the pipeline and midstream business

2016 compared to 2015 The Company recognized consolidated earnings of \$63.7€million in 2016, compared to a consolidated loss of \$623.1€million in 2015. This increase was due to:

f Discontinued operations which reflect the absence in 2016 of fair value impairments of the exploration and production business's assets of \$475.4€million (after tax) and a noncash write-down of oil and natural gas properties of \$315.3€million (after tax) offset in part by a fair value impairment of the refining business of \$156.7€million (after tax) in 2016

f Higher construction, asphalt product and aggregate margins at the construction materials and contracting business

f Other loss decreased primarily as the result of lower operation and maintenance and interest expense due to the sales of the exploration and production and refining businesses

f Higher inside construction margins offset in part by lower outside construction margins, which includes lower equipment sales and rental margins, at the construction services business

f Lower impairment in 2016 at the pipeline and midstream business

f Higher electric retail sales margins offset in part by higher operation and maintenance expense and higher depreciation, depletion and amortization expense at the electric business

Business Segment Financial and Operating Data

Following are key financial and operating data for each of the Company's business segments. Also included are highlights on key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters of the Company's business segments. 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.

For information pertinent to various commitments and contingencies, see Item€8 - Notes to Consolidated Financial Statements. For a summary of the Company's business segments, see Item 8 - Note€13.

Electric and Natural Gas Distribution

Strategy and challenges The electric and natural gas distribution segments provide electric and natural gas distribution services to customers, as discussed in Items 1 and 2 - Business Properties. Both segments strive to be a top performing utility company measured by integrity, safety, employees, customer service and shareholder performance, while continuing to focus on providing safe, reliable and competitively priced energy and related services to customers. The Company continues to monitor opportunities for these segments 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 to earn a competitive return on investment. The continued efforts to create operational improvements and efficiencies across both segments promotes the Company's business integration strategy. The primary factors that impact the results of these segments are the ability to earn authorized rates of return, the cost of natural gas, cost of electric fuel and purchased power competitive factors in the energy industry and economic conditions in the segments' service areas.

The electric and natural gas distribution segments are subject to extensive regulation in the jurisdictions where they conduct operations with respect to costs, timely recovery of investments and permitted returns on investment as well as certain operational, system integrity and environmental regulations. To assist in the reduction of regulatory lag with the increase in investments, tracking mechanisms have been implemented. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas and result in the retirement of certain electric generating facilities before they are fully depreciated. Although the current administration has slowed environmental regulations, the segments continue to invest in facility upgrades to be in compliance with the existing and future regulations.

The ability to grow through acquisitions is subject to significant competition and acquisition premiums. In addition, the ability of the segments to grow their 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.

Revenues are impacted by both customer growth and usage, the latter of which is primarily impacted by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among residential and commercial customers. Average consumption among natural gas customers has tended to decline as more efficient

appliances and furnaces are installed, and as the Company has implemented conservation programs. Decoupling mechanisms in certain jurisdictions have been implemented to largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns.

Earnings overview - electric The following information summarizes the performance of the electric segment.

Years ended December 31,	2017	2016	2015
	(Dollars in millions, where applicable)		
Operating revenues	\$ 342.8	\$ 322.3	\$ 280.6
Operating expenses:			
Operation and maintenance	120.0	115.2	87.7
Electric fuel and purchased power	78.7	75.5	86.2
Depreciation, depletion and amortization	47.7	50.2	37.6
Taxes, other than income	14.3	12.9	11.1
Total operating expenses	260.7	253.8	222.6
Operating income	82.1	68.5	58.0
Earnings	\$ 49.4	\$ 42.2	\$ 35.9
Retail sales (million kWh):			
Residential	1,153.5	1,132.5	1,173.9
Commercial	1,513.1	1,491.8	1,499.6
Industrial	539.9	544.2	550.3
Other	100.0	90.0	92.2
	3,306.5	3,258.5	3,316.0
Average cost of electric fuel and purchased power per kWh	\$.022	\$.021	\$.024

2017 compared to 2016 Electric earnings increased \$7.2€million (17€percent) compared to the prior year. The increase resulted from:

- f Increased electric retail sales margins from the recovery of additional investment in a MISO multivalue project, approved rate recovery in all jurisdictions and 2€percent higher retail sales volumes to commercial and residential customers
- f Lower depreciation, depletion and amortization expense of \$1.5€million (after tax) from lower depreciation rates implemented in conjunction with regulatory recovery activity

Partially offsetting the increase were:

- f Higher operation and maintenance expense of \$3.0€million (after tax) largely from higher payroll-related costs, material costs and contract services
- f Income tax expense of \$2.1 million for the revaluation of nonutility net deferred tax assets, as discussed in Item€8 - Note 11

2016 compared to 2015 Electric earnings increased \$6.3€million (18€percent) compared to the prior year due to:

- f Increased electric retail sales margins, largely due to approved final and interim rate increases reduced in part by decreased electric sales volumes of 2€percent, largely from decreased residential customer volumes
- f Favorable income tax changes, which includes \$10.1€million due to higher production tax credits

Partially offsetting these increases were:

- f Higher operation and maintenance expense of \$17.1€million (after tax) primarily due to higher contract services and higher payroll-related costs
- f Higher depreciation, depletion and amortization expense of \$7.8€million (after tax) due to increased property, plant and equipment balances
- f Lower other income, which includes \$7.1€million (after tax) primarily related to AFUDC
- f Higher interest expense, which includes \$4.4 million (after tax) largely the result of higher long-term debt

Certain of the higher operation and maintenance expense, higher depreciation, depletion and amortization expense and higher production tax credits in 2016, due to increased capital investments, are potentially recoverable and/or refundable through the rate recovery process. The previous table also reflects lower average cost of electric fuel and purchased power per kWh due to no electric fuel and purchased power costs associated with the Thunder Spirit Wind farm in 2016 as compared to 2015.

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Earnings overview - natural gas distribution The following information summarizes the performance of the natural gas distribution segment.

Years ended December 31,	2017	2016	2015
	(Dollars in millions, where applicable)		
Operating revenues	\$ 848.4	\$ 766.1	\$ 817.4
Operating expenses:			
Operation and maintenance	163.7	158.1	153.5
Purchased natural gas sold	479.9	431.5	499.0
Depreciation, depletion and amortization	69.4	65.4	64.8
Taxes, other than income	50.5	46.1	46.3
Total operating expenses	763.5	701.1	763.6
Operating income	84.9	65.0	53.8
Earnings	\$ 32.2	\$ 27.1	\$ 23.6
Volumes (MMdk)			
Retail sales:			
Residential	63.6	56.2	54.0
Commercial	44.3	38.9	37.6
Industrial	4.6	4.2	4.0
	112.5	99.3	95.6
Transportation sales:			
Commercial	2.0	1.8	1.8
Industrial	142.5	145.8	152.4
	144.5	147.6	154.2
Total throughput	257.0	246.9	249.8
Degree days (% of normal)*			
Montana-Dakota/Great Plains	100%	89%	88%
Cascade	107%	87%	83%
Intermountain	111%	96%	89%
Average cost of natural gas, including transportation, per dk	\$ 4.26	\$ 4.35	\$ 5.22

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

2017 compared to 2016 The natural gas distribution business experienced an increase in earnings of \$5.1€million (19€percent) compared to the prior year because of increased natural gas retail sales margins. The margin increase resulted from:

- f Increased retail sales volumes of 13€percent across all customer classes from colder weather in all jurisdictions, offset in part by weather normalization in certain jurisdictions, and 2€percent customer growth
- f Approved final and interim rate increases

Partially offsetting the increase were:

- f Income tax expense of \$4.3€million for the revaluation of nonutility net deferred tax assets, as discussed in Item€8 - Note 11
- f Higher operation and maintenance expense, which includes \$3.7€million (after tax) largely from higher payroll-related costs and material costs
- f Higher depreciation, depletion and amortization expense of \$2.4€million (after tax) as a result of increased property, plant and equipment balances

2016 compared to 2015 The natural gas distribution business experienced an increase in earnings of \$3.5€million (15€percent) compared to the prior year from higher natural gas retail sales margins. The margin increase resulted from:

- f Increased retail sales volumes of 4€percent to all customer classes from customer growth and colder weather in certain regions
- f Approved final and interim rate increases

Partially offsetting the increase were higher operation and maintenance expense, which includes \$4.6€million (after tax) largely from higher payroll-related costs, and higher depreciation, depletion and amortization expense from increased property, plant and equipment balances.

The previous table also includes lower nonutility project costs reflected in operation and maintenance expense, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold in 2016.

OutlookThe Company expects these segments will grow rate base by approximately 6€percent annually over the next five years on a compound basis. This growth projection is on a much larger base, having grown rate base at a record pace of 12€percent compounded annually over the past five-year period. Operations are spread across eight states where the Company expects customer growth to be higher than the national average. Customer growth is expected to grow by 1€percent to 2€percent per year. This customer growth, along with system upgrades and replacements needed to supply safe and reliable service, will require investments in new electric generation and transmission and natural gas systems.

The Company continues to be focused on the regulatory recovery of its investments. Since, January 1, 2017, these segments have implemented rate increases in Idaho, Minnesota, Montana, North Dakota, Oregon, Wyoming and before the FERC. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in Item€8 - Note 16.

With the enactment of the TCJA, the state regulators in jurisdictions where the segments operate have requested companies submit plans for the estimated impact of the TCJA. As such, the segments are using the deferral method of accounting for the revaluation of its regulated deferred tax assets and liabilities. The impact of the revaluation of the segments' regulatory deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment, have been included in the Company's regulatory assets and liabilities, as discussed in Item€8 - Note 4. The Company does not anticipate the corporate tax rate reduction to increase earnings at the utility businesses. The Company anticipates the TCJA will negatively impact the segments' cash flows due to not being able to immediately expense utility property.

In December 2016, the Company signed a 25-year agreement to purchase power from the expansion of the Thunder Spirit Wind farm in southwest North Dakota. In November 2017, the NDPSC approved the advance determination of prudence for the purchase of the Thunder Spirit Wind farm expansion. The Company expects to soon have a purchase agreement in place and finalize the purchase when the construction is complete in late 2018. With the addition of the expansion, the Company's total wind farm generation capacity will be approximately 155 MW and increase the Company's electric generation portfolio to approximately 27€percent renewables based on nameplate ratings. The Company's integrated resource plans in North Dakota and Montana include additional generation projects.

In June 2016, the Company, along with a partner, began construction on a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota. The estimated capital investment for this project is \$130€million to \$150€million. All necessary easements have been secured and the project is expected to be completed in 2019.

In 2018, the Company will begin the construction of a new 12-inch natural gas pipeline that will run approximately 21 miles from northeast Milnor, North Dakota, to southwest of Gwinner, North Dakota. The pipeline will serve, in part, a manufacturing facility in Gwinner and is expected to be in service by late 2018. The pipeline has the capacity to expand natural gas service to other key industries in the region.

Pipeline and Midstream

Strategy and challengesThe pipeline and midstream segment provides natural gas transportation, gathering and underground storage services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on utilizing its extensive expertise in the design, construction and operation of energy infrastructure and related services to increase market share and profitability through optimization of existing operations, organic growth, and investments in energy-related assets within or in close proximity to its current operating areas. The segment focuses on the continual safety and reliability of its systems, which entails building and maintaining safe natural gas pipelines and facilities. The segment continues to evaluate growth opportunities including the expansion of existing storage, gathering and transmission facilities; incremental pipeline projects which expand pipeline capacity; and expansion of energy-related services in the region leveraging on core competencies.

The segment is exposed to energy price volatility which is impacted by the fluctuations in pricing, production and basis differentials of the energy market's commodities. Legislative and regulatory initiatives to increase pipeline safety regulations and reduce methane emissions could also impact the price and demand for natural gas.

The pipeline and midstream segment is subject to extensive regulation including certain operational, system integrity and environmental regulations as well as various permit terms and operational compliance conditions. The segment is charged with the ongoing process of reviewing existing permits and easements as well as securing new permits and easements as necessary to meet current demand and future

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growth opportunities. Exposure to pipeline opposition groups could also cause negative impacts on the segment with increased costs and potential delays to project completion.

The segment focuses on the recruitment and retention of a skilled workforce to remain competitive and provide services to its customers. The industry in which it operates relies on a skilled workforce to construct energy infrastructure and operate existing infrastructure in a safe manner. A shortage of skilled personnel can create a competitive labor market which could increase costs incurred by the segment. Competition from other pipeline and midstream companies can also have a negative impact on the segment.

Earnings overview - pipeline and midstream The following information summarizes the performance of the pipeline and midstream segment.

Years ended December 31,	2017	2016	2015
	(Dollars in millions)		
Operating revenues	\$ 122.2	\$ 141.6	\$ 154.9
Operating expenses:			
Operation and maintenance	56.0	61.4	84.7
Depreciation, depletion and amortization	16.8	24.9	28.0
Taxes, other than income	12.5	11.9	12.2
Total operating expenses	85.3	98.2	124.9
Operating income	36.9	43.4	30.0
Earnings	\$ 20.5	\$ 23.4	\$ 13.3
Transportation volumes (MMdk)	312.5	285.3	290.5
Natural gas gathering volumes (MMdk)	16.1	20.0	33.4
Customer natural gas storage balance (MMdk):			
Beginning of period	26.4	16.6	14.9
Net injection (withdrawal)	(4.0)	9.8	1.7
End of period	22.4	26.4	16.6

2017 compared to 2016 Pipeline and midstream earnings decreased \$2.9€million (13€percent) compared to the prior year largely resulting from lower gathering and processing revenues of \$14.0€million (after tax). The decrease in revenues resulted from lower volumes from the sale of the Pronghorn assets in January 2017, as discussed in Item€8 - Note 2. Also included in the decrease in earnings was income tax expense of \$200,000 for the TCJA revaluation, as discussed in Item€8 - Note 11.

Partially offsetting the decrease were:

- f Lower depreciation, depletion and amortization expense of \$5.0€million (after tax) resulting from the absence of the Pronghorn assets, as previously discussed
- f Lower operation and maintenance expense, which includes \$2.2€million (after tax) primarily from the absence of Pronghorn, as previously discussed, as well as the absence in 2017 of a \$1.4€million (after tax) fair value impairment in 2016 associated with the Pronghorn sale
- f Lower interest expense due to lower debt balances
- f Higher transportation revenues of \$1.0€million largely resulting from increased off-system transportation volumes due to recently completed organic growth projects

2016 compared to 2015 Pipeline and midstream earnings increased \$10.1€million (77€percent) largely due to:

- f Lower operation and maintenance expense, which includes \$13.6€million (after tax) largely due to the absence in 2016 of impairments of natural gas gathering assets of \$10.6€million (after tax), as discussed in Item 8 - Notes 1 and 5, lower payroll-related costs and lower material costs partially offset by a fair value impairment in 2016 of \$1.4€million (after tax) associated with the sale of Pronghorn, as previously discussed
- f Lower depreciation, depletion and amortization of \$1.9€million (after tax), largely due to the sale of certain non-strategic natural gas gathering assets in the fourth quarter of 2015
- f Higher storage services earnings, primarily due to higher average interruptible storage balances
- f Lower interest expense of \$1.2€million (after tax), primarily the result of lower debt interest rates and balances

Partially offsetting the earnings increase was lower gathering and processing revenues of \$8.0€million (after tax) resulting from lower natural gas gathering volumes, primarily due to the sale of certain non-strategic natural gas gathering assets, as previously discussed, and lower oil gathering volumes, partially offset by higher oil gathering rates at Pronghorn.

OutlookThe Company has continued to feel the effects of natural gas production at record levels which keeps downward pressure on natural gas prices in the near term. The Company continues to focus on growth and improving existing operations through organic projects in all areas in which it operates. The following describes recent growth projects.

The Company's Valley Expansion project, a 38-mile pipeline that will deliver natural gas supply to eastern North Dakota and far western Minnesota, is expected to be complete in the fourth quarter of 2018. The project, which is designed to transport 40 million cubic feet of natural gas per day, is under the jurisdiction of the FERC. In February 2018, the Company received an order issuing a certificate of public convenience and necessity from the FERC. Construction is expected to begin as soon as the conditions of the certificate have been met, including the receipt of outstanding permits.

In June 2017, the Company announced plans to complete a Line Section 27 expansion project in the Bakken area of northwestern North Dakota. The project will include approximately 13 miles of new pipeline and associated facilities. The project, as designed, will increase capacity by over 200 million cubic feet per day and bring total capacity of the Line Section 27 to over 600 million cubic feet per day. The project is expected to be placed in service in the fall of 2018.

In 2017, the Company completed and placed into service the Charbonneau and Line Section 25 expansion projects, which include a new compression station as well as other compressor additions and enhancements at existing stations. The Company's revenues have been positively impacted by the increase in transportation volumes with these projects.

The impact of the TCJA on the pipeline and midstream industry is uncertain. With the enactment of the TCJA, the regulated pipeline is using the deferral method of accounting for the revaluation of its regulated deferred tax assets and liabilities. The impact of the revaluation of the regulated pipeline's regulatory deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment, have been included in the Company's regulatory assets and liabilities, as discussed in Item 8 - Note 4.

Construction Materials and Contracting

Strategy and challengesThe construction materials and contracting segment provides an integrated set of construction services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthening the long-term, strategic aggregate reserve position through available purchase and/or lease opportunities; enhancing profitability through cost containment, margin discipline and vertical integration of the segment's operations; development and recruitment of talented employees; and continued growth through organic and acquisition opportunities.

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 segment's expertise. The segment 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.

As one of the country's largest sand and gravel producers, the segment 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. The segment's 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.

The construction materials and contracting segment faces challenges that are not under the direct control of the business. The segment operates in highly competitive markets. Competition can put negative pressure on the ability of the segment to earn a reasonable return. The segment is also subject to volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel. Such volatility can have a negative impact on the segment's margins. Other variables that can impact the segment's margins include adverse weather conditions, the timing of project starts or completion and declines or delays in new and existing projects due to the cyclical nature of the construction industry.

The segment also faces challenges in the recruitment and retention of employees. Trends in the labor market include an aging workforce and availability issues. The segment also faces increasing pressure to reduce costs and the need for temporary employment because of the seasonality of the work performed in certain regions.

Part II

Earnings overview - construction materials and contracting The following information summarizes the performance of the construction materials and contracting segment.

Years ended December 31,	2017	2016	2015
	(Dollars in millions)		
Operating revenues	\$ 1,812.5	\$ 1,874.3	\$ 1,904.3
Operating expenses:			
Cost of sales:			
Operation and maintenance	1,500.7	1,533.2	1,576.4
Depreciation, depletion and amortization	52.5	54.1	61.0
Taxes, other than income	38.0	37.5	36.1
	1,591.2	1,624.8	1,673.5
Selling, general and administrative expense:			
Operation and maintenance	70.4	62.2	75.9
Depreciation, depletion and amortization	3.4	4.3	4.9
Taxes, other than income	3.8	4.3	4.0
	77.6	70.8	84.8
Total operating expenses	1,668.8	1,695.6	1,758.3
Operating income	143.7	178.7	146.0
Earnings	\$ 123.4	\$ 102.7	\$ 89.1
Sales (000's):			
Aggregates (tons)	28,213	27,580	26,959
Asphalt (tons)	6,237	7,203	6,705
Ready-mixed concrete (cubic yards)	3,548	3,655	3,592

2017 compared to 2016 Earnings at the construction materials and contracting business increased \$20.7 million (20 percent) compared to the prior year. The increase was the result of:

- f An income tax benefit of \$41.9 million for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 11
- f Higher aggregate margins of \$5.0 million (after tax) primarily due to strong commercial and residential demand in certain regions

Partially offsetting these increases were:

- f Lower asphalt product margins resulting from lower revenues driven by competitive pricing and lower volumes from unfavorable weather during the first half of the year, less available work and increased competition in certain regions
- f Lower construction margins of \$5.5 million (after tax), largely decreased workloads caused by unfavorable weather during the first half of the year and less available work in energy-producing states
- f Higher selling, general and administrative expense of \$4.1 million (after tax) from the absence in 2017 of a \$6.7 million (after tax) reduction to a MEPP withdrawal liability, as discussed in Item 8 - Note 14, offset in part by lower depreciation, depletion and amortization and lower office expense

2016 compared to 2015 Earnings at the construction materials and contracting business increased \$13.6 million (15 percent) due to:

- f Higher construction margins of \$8.1 million (after tax) resulting from higher revenues due to more available work in most regions
- f Lower selling, general and administrative expense from a \$6.7 million (after tax) reduction in 2016 to a previously recorded MEPP withdrawal liability compared to an increase to a MEPP withdrawal liability of \$1.5 million (after tax) in 2015, as discussed in Item 8 - Note 14
- f Higher asphalt product margins of \$2.9 million (after tax) resulting from higher volumes and lower asphalt oil and production costs
- f Higher aggregate margins of \$2.3 million (after tax) resulting from higher volumes due to increased demand

Partially offsetting these increases were:

- f Higher effective income tax rates
- f Lower other product lines margins of \$1.3 million (after tax)

Lower diesel fuel costs contributed to higher earnings from all product lines in 2016.

OutlookThe segment's vertically integrated aggregates based business model provides the Company with the ability to capture margin throughout the sales delivery process. The aggregate products are sold internally and externally for use in other products such as ready-mixed concrete, asphaltic concrete and public and private construction markets. The contracting services and construction materials are sold primarily to construction contractors in connection with street, highway and other public infrastructure projects, as well as private commercial and residential development projects. The public infrastructure projects have traditionally been more stable markets as public funding is more secure during periods of economic decline. The public funding is, however, dependent on federal funding such as appropriations to the Federal Highway Administration. Spending on private development is highly dependent on both local and national economic cycles, providing additional sales during times of strong economic cycles.

The Company remains optimistic about overall economic growth and infrastructure spending. The IBIS World Industry Report for sand and gravel mining in the United States projects a 2.7% annual growth rate over the next five years. The report also states the demand for clay and refractory materials is projected to continue deteriorating in several downstream manufacturing industries, but this decline will be offset by stronger demand from the housing market and buoyant demand from the highway and bridge construction market. This stronger demand in the housing markets along with continued demand from the highway and bridge construction markets should provide a stable demand for construction materials and contracting products and services in the near future.

The impact of the TCJA on the economy as a whole is unclear at this time. As such, the impact to the construction materials and contracting industry is also uncertain. Under the TCJA, the domestic production deduction will no longer be able to be taken. The domestic production deduction was originally introduced to incentivize domestic production activities and was a deduction of up to 9% on qualified production activity income for which this segment's activities qualified. The Company expects the lower federal corporate tax rate will more than offset the loss of the domestic production deduction for this segment.

Construction Services

Strategy and challengesThe construction services segment provides inside and outside specialty contracting, as discussed in Items 1 and 2 - Business Properties. The construction services segment focuses on providing a superior return on investment by building new and strengthening existing customer relationships; ensuring quality service; safely executing projects; effectively controlling costs; collecting on receivables; retaining, developing and recruiting talented employees; growing through organic and acquisition opportunities; and focusing efforts on projects that will permit higher margins while properly managing risk.

The construction services segment faces challenges in the highly competitive markets in which it operates. Competitive pricing environments, project delays and effects from restrictive regulatory requirements have negatively impacted margins in the past and could affect margins in the future. Additionally, margins may be negatively impacted on a quarterly basis due to adverse weather conditions, as well as timing of project starts or completions, declines or delays in new projects due to the cyclical nature of the construction industry and other factors. These challenges may also impact the risk of loss on certain projects. Accordingly, operating results in any particular period may not be indicative of the results that can be expected for any other period.

The need to ensure available specialized labor resources for projects also drives strategic relationships with customers and project margins. These trends include an aging workforce and labor availability issues, increasing pressure to reduce costs and improve reliability, and increasing duration and complexity of customer capital programs. Due to these and other factors, we believe customer demand for labor resources will continue to increase, possibly outpacing, the supply of industry resources.

Part II

Earnings overview - construction services The following information summarizes the performance of the construction services segment.

Years ended December 31,	2017	2016	2015
	(In millions)		
Operating revenues	\$ 1,367.6	\$ 1,073.3	\$ 926.4
Operating expenses:			
Cost of sales:			
Operation and maintenance	1,153.9	905.4	783.7
Depreciation, depletion and amortization	14.2	13.5	11.8
Taxes, other than income	43.4	35.2	27.4
	1,211.5	954.1	822.9
Selling, general and administrative expense:			
Operation and maintenance	69.0	59.9	54.8
Depreciation, depletion and amortization	1.5	1.8	1.6
Taxes, other than income	4.0	3.8	3.7
	74.5	65.5	60.1
Total operating expenses	1,286.0	1,019.6	883.0
Operating income	81.6	53.7	43.4
Earnings	\$ 53.3	\$ 33.9	\$ 23.8

2017 compared to 2016 Construction services earnings increased \$19.4€million (57€percent) compared to the prior year largely because of:

- f Higher inside specialty contracting margins of \$12.8€million (after tax) driven by an increase in revenues from an increase in the number and size of construction projects in 2017 and decreased costs from the successful management of labor performance on projects in a majority of the business activities performed partially offset by job losses on certain projects
- f Higher outside specialty contracting margins of \$9.8€million (after tax) driven by higher contracting workloads and equipment revenues in areas impacted by storm activity
- f An income tax benefit of \$4.3€million for the revaluation of the segment's net deferred tax liabilities, as discussed in Item€8 - Note 11

Partially offsetting these increases were:

- f Higher selling, general and administrative expense, largely payroll-related costs
- f The absence in 2017 of a \$1.5€million tax benefit related to the disposition of a non-strategic asset

2016 compared to 2015 Construction services earnings increased \$10.1€million (43€percent) compared to the prior year largely because of:

- f Higher inside specialty contracting margins of \$13.0€million (after tax) resulting from higher workloads from the successful completion of construction projects in certain markets, as well as lower labor costs due to increased efficiencies and lower workers' compensation claim costs partially offset by a loss on a project
- f Higher margins of \$3.5€million (after tax) resulting from the sale of a non-strategic asset in 2015

These increases were partially offset by:

- f Higher selling, general and administrative expense of \$4.0€million (after tax), primarily due to higher payroll and benefit-related costs and higher bad debt expense
- f Lower outside construction margins, primarily lower equipment revenues impacted by decreased customer demand

OutlookThe Company continues to expect long-term growth in the electric transmission market, although the timing of large bids and subsequent construction is likely to be highly variable from year to year. The Company believes several multi-year transmission projects will be available for bid in the 2018 timeframe and also expects bidding activity in small and medium-sized transmission and distribution projects to continue in 2018.

The impact of the TCJA on the economy as a whole is unclear at this time. As such, the impact to the construction services industry is also uncertain. While it is unclear what impact the TCJA may have on the construction services industry, the Company is optimistic about overall economic growth and infrastructure spending and believes that improving industry activity will continue in both market segments and the drivers for investment will remain intact. The Company believes that regulatory reform, state renewable portfolio standards, the aging of the electric grid, and the general improvement of the economy will positively impact the level of spending by its customers. Although competition remains strong, these trends are viewed as positive factors in the future.

The Company expects bidding activity to remain strong in both outside and inside specialty construction companies for the year 2018. Although bidding remains highly competitive in all areas, the Company expects the segment's skilled workforce will continue to provide a benefit in securing and executing profitable projects.

Other

Years ended December 31,	2017	2016	2015
	(In millions)		
Operating revenues	\$ 7.9	\$ 8.6	\$ 9.2
Operating expenses:			
Operation and maintenance	6.2	6.6	15.4
Depreciation, depletion and amortization	2.0	2.1	2.1
Taxes, other than income	.2	.1	.1
Total operating expenses	8.4	8.8	17.6
Operating loss	(1.5)	(1.2)	(8.4)
Loss	\$ (1.5)	\$ (3.2)	\$ (15.0)

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

2017 compared to 2016 Other loss decreased \$1.7€million compared to the prior year primarily the result of lower interest expense from the repayment of long-term debt with the sale of the remaining exploration and production assets. Lower operation and maintenance expense was due to the absence of the refining business in 2017 offset in part by the loss on the disposition of certain assets during the year.

2016 compared to 2015 Other loss decreased \$11.8€million compared to the prior year primarily due to lower operation and maintenance expense and interest expense previously allocated to the exploration and production business, due to the sale of that business which included the repayment of long-term debt. Also contributing to the decreased loss was lower operation and maintenance expense in 2016 due to the absence of a 2015 corporate asset impairment and the absence of a 2015 foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

Discontinued Operations

Years ended December 31,	2017	2016	2015
	(In millions)		
Income (loss) from discontinued operations before intercompany eliminations, net of tax	\$ 3.1	\$ (303.2)	\$ (829.9)
Intercompany eliminations*	(6.9)	2.8	(4.2)
Loss from discontinued operations, net of tax	(3.8)	(300.4)	(834.1)
Loss from discontinued operations attributable to noncontrolling interest	•	(131.7)	(35.3)
Loss from discontinued operations attributable to the Company, net of tax	\$ (3.8)	\$ (168.7)	\$ (798.8)

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

2017 compared to 2016 The loss from discontinued operations attributable to the Company was \$3.8€million compared to a loss of \$168.7€million in the prior year. The decreased loss was largely due to the absence in 2017 of a loss associated with the sale of the refining business in June 2016, as well as the reversal in 2017 of a previously accrued liability due to the resolution of a legal matter, as discussed in Item 8 - Note 2.

2016 compared to 2015 The loss from discontinued operations attributable to the Company was \$168.7€million compared to a loss of \$798.8€million in the prior year. The decreased loss is primarily due to the completion of the sales of Company's exploration and production and refining businesses. The decreased loss was largely the result of the absence in 2016 of a noncash write-down of oil and natural gas properties of \$315.3 million (after tax) and fair value impairments of the exploration and production business's assets held for sale of \$475.4€million (after tax), as discussed in Item 8 - Note 2, partially offset by a fair value impairment of the refining business of \$156.7€million (after tax) in 2016, as discussed in Item 8 - Note 2.

Part II

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 related to these items were as follows:

Years ended December 31,	2017	2016	2015
	(In millions)		
Intersegment transactions:			
Operating revenues	\$ 58.0	\$ 57.4	\$ 78.8
Operation and maintenance	9.1	8.7	26.9
Purchased natural gas sold	48.9	48.7	48.9
Income from continuing operations*	(6.9)	(6.3)	(5.0)

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

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

New Accounting Standards

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

Liquidity and Capital Commitments

At December 31, 2017, the Company had cash and cash equivalents of \$34.6 million and available borrowing capacity of \$687.1 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 and its other operating and capital requirements from various sources, including internally generated funds; the Company's credit facilities, as described later in Capital resources; the issuance of long-term debt; and issuance of equity securities.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Business Segment Financial and Operating Data and also are affected by changes in working capital. Changes in cash flows for discontinued operations are related to the former exploration and production and refining businesses.

Cash flows provided by operating activities in 2017 decreased \$14.2 million from 2016. The decrease in cash flows provided by operating activities reflects higher working capital requirements at the construction services business largely resulting from higher receivables due to increased workloads during the year and at the construction materials business due to higher receivables resulting from increased workloads later in the year. Higher natural gas purchases including the effects of colder weather also added to higher working capital requirements at the natural gas distribution business. Higher income taxes paid from continuing operations was largely offset by higher income taxes received from discontinued operations resulting from the realization of net operating losses at the discontinued operations. Higher earnings from continuing operations in 2017, compared to 2016, partially offset the decrease in cash flows provided by operating activities. Higher margins at the electric, natural gas distribution and construction services businesses were partially offset by lower margins at the construction materials business.

Cash flows provided by operating activities in 2016 decreased \$199.6 million from 2015. The decrease in cash flows provided by operating activities was largely from lower cash flows at the exploration and production business. The decrease was also due to higher working capital requirements at the electric, natural gas distribution and pipeline and midstream businesses. Partially offsetting the decrease in cash flows provided by operating activities was higher cash flows from continuing operations (excluding working capital) at the electric, pipeline and midstream and construction materials and contracting businesses.

Investing activities Cash flows used in investing activities in 2017 decreased \$90.9 million from 2016 largely resulting from net proceeds from the sale of Pronghorn in January 2017 at the pipeline and midstream business.

Cash flows used in investing activities in 2016 decreased \$77.4 million from 2015 primarily due to lower capital expenditures largely at the electric and refining businesses. Partially offsetting this decrease were lower proceeds from the sale of properties at the exploration and production business.

Financing activities Cash flows used in financing activities in 2017 increased \$50.4 million from 2016 primarily due to the higher net repayment of long-term debt.

Cash flows used in financing activities in 2016 decreased \$60.8€million from 2015 primarily due to the lower repayment of long-term debt of \$250.9 million, partially offset by debt repayment in connection with the sale of the refining business, lower capital contributions at the refining business and lower issuance of long-term debt of \$36.9 million.

Defined benefit pension plans

The Company has noncontributory qualified 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, 2017, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately \$91.5 million. Pretax pension expense reflected in the years ended December€31, 2017, 2016 and 2015, was \$1.7 million, \$2.1€million and \$2.0€million, respectively. The Company's pension expense is currently projected to be approximately \$2.0€million to \$3.0€million in 2018. Funding for the pension plans is actuarially determined. The minimum required contributions for 2017 and 2015 were approximately \$3.1 million and \$3.9€million, respectively. There were no minimum required contributions for 2016. For more information on the Company's pension plans, see Item€8 - Note€14.

Capital expenditures

The Company's capital expenditures from continuing operations for 2015 through 2017 and as anticipated for 2018 through 2020 are summarized in the following table.

	Actual (a)			Estimated		
	2015	2016	2017	2018	2019	2020
	(In millions)					
Capital expenditures:						
Electric	\$ 333	\$ 111	\$ 109	\$ 229	\$ 107	\$ 98
Natural gas distribution	131	126	147	203	211	172
Pipeline and midstream	18	35	31	97	100	109
Construction materials and contracting	48	38	44	79	78	76
Construction services	38	60	19	17	16	16
Other	4	2	2	3	2	1
Total capital expenditures	\$ 572	\$ 372	\$ 352	\$ 628	\$ 514	\$ 472

(a) Capital expenditures for 2017, 2016 and 2015 include noncash capital expenditure-related accounts payable and AFUDC, totaling \$10.5€million, \$(15.8)€million and \$35.3€million, respectively.

The 2017 capital expenditures were met from internal sources. The Company has included in the estimated capital expenditures for 2018 the purchase of the Thunder Spirit Wind farm expansion, the Valley Expansion project and the Line Section 27 expansion project, as previously discussed in Business Segment Financial and Operating Data.

Estimated capital expenditures for the years 2018 through 2020 include those for:

- f System upgrades
- f Routine replacements
- f Service extensions
- f Routine equipment maintenance and replacements
- f Buildings, land and building improvements
- f Pipeline, gathering and other midstream projects
- f Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- f Environmental upgrades
- f 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 for the years 2018 through 2020 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; issuance of long-term debt; and issuance of equity securities.

Part II

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, 2017. 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 6.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2017:

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	\$	73.8	(b)	\$,		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		\$ 75.0	(c)	\$ 17.3		\$ 2.2	(d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		\$ 85.0	(e)	\$ 40.0		\$,		4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	\$ 500.0	\$	14.6	(b)	\$,		9/23/21

(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 revolving credit agreement.

(b) Amount outstanding under commercial paper program.

(c) Certain provisions allow for increased borrowings, up to a maximum of \$100.0 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 \$110.0 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 \$600.0 million). There were no amounts outstanding under the revolving 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 Company's coverage of fixed charges including preferred stock dividends was 4.2 times and 3.9 times for the 12 months ended December 31, 2017 and 2016, respectively. The coverage of fixed charges is used as an indicator of the Company's ability to satisfy fixed charges.

Total equity as a percent of total capitalization was 59 percent and 56 percent at December 31, 2017 and 2016, 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 is an indicator of how the Company is financing its operations, as well as its financial strength.

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. Historically, 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 in the future, 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.

Cascade Natural Gas Corporation On April 25, 2017, Cascade amended its revolving credit agreement to increase the borrowing limit from \$50.0 million to \$75.0 million and extend the termination date from July 9, 2018 to April 24, 2020. The credit agreement contains

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

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

On April 25, 2017, Intermountain amended its revolving credit agreement to increase the borrowing limit from \$65.0 million to \$85.0 million and extend the termination date from July 13, 2018 to April 24, 2020. 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 objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Historically, 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 in the future, 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 \$200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had \$100.0 million of notes outstanding at December 31, 2017, which reduced the remaining capacity under this uncommitted private shelf agreement to \$100.0 million. On December 22, 2017, WBI Energy Transmission contracted to issue an additional \$40.0 million under the private shelf agreement at an interest rate of 4.18 percent on June 15, 2018.

Off balance sheet arrangements

As of December 31, 2017, the Company had no material off balance sheet arrangements as defined by the rules of the SEC.

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 6 and 17. At December 31, 2017, the Company's commitments under these obligations were as follows:

	2018	2019	2020	2021	2022	Thereafter	Total
	(In millions)						
Long-term debt	\$ 148.5	\$ 125.5	\$ 73.0	\$ 15.3	\$ 147.2	\$ 1,211.0	\$ 1,720.5
Estimated interest payments*	71.2	62.6	62.2	59.1	58.7	512.9	826.7
Operating leases	55.5	45.3	33.2	18.6	7.0	40.8	200.4
Purchase commitments	360.8	215.0	162.4	135.3	99.1	773.8	1,746.4
	\$ 636.0	\$ 448.4	\$ 330.8	\$ 228.3	\$ 312.0	\$ 2,538.5	\$ 4,494.0

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

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At December 31, 2017, the Company had total liabilities of \$342.0 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was \$4.3 million at December 31, 2017, 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 deferred credits and other liabilities - other 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 7.

The Company has no uncertain tax positions in 2018.

The Company's minimum funding requirements for its defined benefit pension plans for 2018, which are not reflected in the previous table, are \$3.1 million. For information on potential contributions above the funding minimum requirements, see item 8 - Note 14.

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.

Critical Accounting Policies Involving Significant Estimates

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

Estimates are used for items such as impairment testing of long-lived assets and goodwill; 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.

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, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and at least annually for goodwill.

GoodwillThe 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, 2017, 2016, and 2015, there were no significant impairment losses recorded. At December 31, 2017, 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 2017. 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.

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 2017.

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

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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 \$1.5 million (after tax) for the year ended December 31, 2017.

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

The Company is required to make judgments regarding the potential tax effects of various financial transactions and ongoing operations to estimate the Company's obligation to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements of a tax position that is more-likely-than-not to be sustained on audit.

Judgment and estimation is required in developing the provision for income taxes and the reporting of tax-related assets and liabilities and, if necessary, any valuation allowances. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income tax could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states.

The Company assesses the deferred tax assets for recoverability taking into consideration historical and anticipated earnings levels; the reversal of other existing temporary differences; available net operating losses and tax carryforwards; and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against the deferred tax assets. As facts and circumstances change, adjustment to the valuation allowance may be required.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2017, 2016 or 2015.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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 has utilized 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. For additional information on the Company's long-term debt, see Item 8 - Notes 5 and 6.

At December 31, 2017 and 2016, the Company had no outstanding interest rate hedges.

The following table shows the amount of long-term debt, which excludes unamortized debt issuance costs and discount, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2017.

	2018	2019	2020	2021	2022	Thereafter	Total	Fair Value
	(Dollars in millions)							
Long-term debt:								
Fixed rate	\$ 148.5	\$ 51.7	\$ 15.7	\$.7	\$ 147.2	\$ 1,211.0	\$ 1,574.8	\$ 1,680.6
Weighted average interest rate	6.1%	4.3%	5.1%	2.1%	4.5%	4.7%	4.8%	,
Variable rate	,	\$ 73.8	\$ 57.3	\$ 14.6	,	,	\$ 145.7	\$ 145.7
Weighted average interest rate	,	1.7%	3.7%	1.9%	,	,	2.5%	,

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, 2017. 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, 2017.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2017, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.



David L. Goodin
President and Chief Executive Officer



Jason L. Vollmer
Vice President, Chief Financial Officer and Treasurer

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits include performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.



Minneapolis, Minnesota

February 23, 2018

We have served as the Company's auditor since 2002.

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Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2017, of the Company and our report dated February 23, 2018, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. 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 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.



Minneapolis, Minnesota

February 23, 2018

Consolidated Statements of Income

Years ended December 31,	2017	2016	2015
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	\$ 1,244,759	\$ 1,141,454	\$ 1,149,038
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	3,198,592	2,987,374	2,865,014
Total operating revenues	4,443,351	4,128,828	4,014,052
Operating expenses:			
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	323,120	312,404	278,171
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	2,807,682	2,580,895	2,527,052
Total operation and maintenance	3,130,802	2,893,299	2,805,223
Purchased natural gas sold	430,954	382,753	450,114
Depreciation, depletion and amortization	207,486	216,318	211,747
Taxes, other than income	166,673	151,826	140,955
Electric fuel and purchased power	78,724	75,512	86,238
Total operating expenses	4,014,639	3,719,708	3,694,277
Operating income	428,712	409,120	319,775
Other income	4,103	4,956	18,457
Interest expense	82,788	87,848	91,179
Income before income taxes	350,027	326,228	247,053
Income taxes	65,041	93,132	70,664
Income from continuing operations	284,986	233,096	176,389
Loss from discontinued operations, net of tax (Note 2)	(3,783)	(300,354)	(834,080)
Net income (loss)	281,203	(67,258)	(657,691)
Loss from discontinued operations attributable to noncontrolling interest (Note 2)	•	(131,691)	(35,256)
Loss on redemption of preferred stocks (Note 8)	600	,	,
Dividends declared on preferred stocks	171	685	685
Earnings (loss) on common stock	\$ 280,432	\$ 63,748	\$ (623,120)
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	\$ 1.46	\$ 1.19	\$.90
Discontinued operations attributable to the Company, net of tax	(.02)	(.86)	(4.10)
Earnings (loss) per common share - basic	\$ 1.44	\$.33	\$ (3.20)
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	\$ 1.45	\$ 1.19	\$.90
Discontinued operations attributable to the Company, net of tax	(.02)	(.86)	(4.10)
Earnings (loss) per common share - diluted	\$ 1.43	\$.33	\$ (3.20)
Weighted average common shares outstanding - basic	195,304	195,299	194,928
Weighted average common shares outstanding - diluted	195,687	195,618	194,986

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

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Consolidated Statements of Comprehensive Income

Years ended December 31,	2017	2016	2015
	(In thousands)		
Net income (loss)	\$ 281,203	\$ (67,258)	\$ (657,691)
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of \$224, \$226 and \$233 in 2017, 2016 and 2015, respectively	366	367	404
Postretirement liability adjustment:			
Postretirement liability losses arising during the period, net of tax of \$(1,162), \$(836) and \$(55) in 2017, 2016 and 2015, respectively	(1,812)	(1,470)	(88)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of \$645, \$1,425 and \$1,128 in 2017, 2016 and 2015, respectively	1,013	2,506	1,794
Reclassification of postretirement liability adjustment (from) to regulatory asset, net of tax of \$(876), \$0 and \$1,416 in 2017, 2016 and 2015, respectively	(1,143)	,	2,255
Postretirement liability adjustment	(1,942)	1,036	3,961
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of \$(3), \$31 and \$(105) in 2017, 2016 and 2015, respectively	(6)	51	(173)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of \$0, \$0 and \$490 in 2017, 2016 and 2015, respectively	•	,	802
Foreign currency translation adjustment	(6)	51	629
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of \$(75), \$(98) and \$(91) in 2017, 2016 and 2015, respectively	(139)	(182)	(170)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of \$65, \$77 and \$70 in 2017, 2016 and 2015, respectively	120	143	131
Net unrealized loss on available-for-sale investments	(19)	(39)	(39)
Other comprehensive income (loss)	(1,601)	1,415	4,955
Comprehensive income (loss)	279,602	(65,843)	(652,736)
Comprehensive loss from discontinued operations attributable to noncontrolling interest	•	(131,691)	(35,256)
Comprehensive income (loss) attributable to common stockholders	\$ 279,602	\$ 65,848	\$ (617,480)

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

Consolidated Balance Sheets

December€31,	2017	2016
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	\$ 34,599	\$ 46,107
Receivables, net	727,030	630,243
Inventories	226,583	238,273
Prepayments and other current assets	81,304	48,461
Current assets held for sale	479	14,391
Total current assets	1,069,995	977,475
Investments		
Property, plant and equipment (Note 1)	6,770,829	6,510,229
Less accumulated depreciation, depletion and amortization	2,691,641	2,578,902
Net property, plant and equipment	4,079,188	3,931,327
Deferred charges and other assets:		
Goodwill (Note 3)	631,791	631,791
Other intangible assets, net (Note 3)	3,837	5,925
Other	407,850	415,419
Noncurrent assets held for sale	4,392	196,664
Total deferred charges and other assets	1,047,870	1,249,799
Total assets	\$ 6,334,666	\$ 6,284,467
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	\$ 148,499	\$ 43,598
Accounts payable	312,327	279,962
Taxes payable	42,537	48,164
Dividends payable	38,573	37,767
Accrued compensation	72,919	65,867
Other accrued liabilities	186,010	184,377
Current liabilities held for sale	11,993	9,924
Total current liabilities	812,858	669,659
Long-term debt (Note 6)	1,566,354	1,746,561
Deferred credits and other liabilities:		
Deferred income taxes	347,271	668,226
Other	1,179,140	883,777
Total deferred credits and other liabilities	1,526,411	1,552,003
Commitments and contingencies (Notes 14, 16 and 17)		
Stockholders' equity:		
Preferred stocks (Note 8)	•	15,000
Common stockholders' equity:		
Common stock (Note 9)		
Authorized - 500,000,000 shares, \$1.00 par value	195,843	195,843
Issued - 195,843,297 shares in 2017 and 2016		
Other paid-in capital	1,233,412	1,232,478
Retained earnings	1,040,748	912,282
Accumulated other comprehensive loss	(37,334)	(35,733)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,429,043	2,301,244
Total stockholders' equity	2,429,043	2,316,244
Total liabilities and stockholders' equity	\$ 6,334,666	\$ 6,284,467

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

Part II

Consolidated Statements of Equity

Years ended December 31, 2017, 2016 and 2015

	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, 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
Net income (loss)	,	,	,	,	,	64,433	,	,	,	(131,691)	(67,258)
Other comprehensive income	,	,	,	,	,	,	1,415	,	,	,	1,415
Dividends declared on preferred stocks	,	,	,	,	,	(685)	,	,	,	,	(685)
Dividends declared on common stock	,	,	,	,	,	(147,821)	,	,	,	,	(147,821)
Stock-based compensation	,	,	,	,	4,383	,	,	,	,	,	4,383
Net tax deficit on stock-based compensation	,	,	,	,	(1,663)	,	,	,	,	,	(1,663)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	,	,	38,632	38	(361)	,	,	,	,	,	(323)
Contribution from noncontrolling interest	,	,	,	,	,	,	,	,	7,648	,	7,648
Balance at											
December 31, 2016	150,000	15,000	195,843,297	195,843	1,232,478	912,282	(35,733)	(538,921)	(3,626)	,	2,316,244
Net income	,	,	,	,	,	281,203	,	,	,	,	281,203
Other comprehensive loss	,	,	,	,	,	,	(1,601)	,	,	,	(1,601)
Dividends declared on preferred stocks	,	,	,	,	,	(171)	,	,	,	,	(171)
Dividends declared on common stock	,	,	,	,	,	(151,966)	,	,	,	,	(151,966)
Stock-based compensation	,	,	,	,	3,375	,	,	,	,	,	3,375
Repurchase of common stock	,	,	,	,	,	,	,	(64,384)	(1,684)	,	(1,684)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	,	,	,	,	(2,441)	,	,	64,384	1,684	,	(757)
Redemption of preferred stock	(150,000)	(15,000)	,	,	,	(600)	,	,	,	,	(15,600)
Balance at											
December 31, 2017		\$	195,843,297	\$195,843	\$1,233,412	\$1,040,748	\$(37,334)	(538,921)	\$(3,626)	\$	\$2,429,043

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

Consolidated Statements of Cash Flows

Years ended December 31,	2017	2016	2015
	(In thousands)		
Operating activities:			
Net income (loss)	\$ 281,203	\$ (67,258)	\$ (657,691)
Loss from discontinued operations, net of tax	(3,783)	(300,354)	(834,080)
Income from continuing operations	284,986	233,096	176,389
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	207,486	216,318	211,747
Deferred income taxes	(25,423)	(2,049)	(25,356)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(108,255)	(25,641)	4,704
Inventories	9,135	2,433	2,265
Other current assets	(30,588)	(17,925)	60,182
Accounts payable	26,013	7,039	37,224
Other current liabilities	4,648	36,146	6,864
Other noncurrent changes	(18,790)	(26,459)	(10,240)
Net cash provided by continuing operations	349,212	422,958	463,779
Net cash provided by discontinued operations	98,799	39,251	198,053
Net cash provided by operating activities	448,011	462,209	661,832
Investing activities:			
Capital expenditures	(341,382)	(388,183)	(536,832)
Net proceeds from sale or disposition of property and other	126,588	44,826	54,569
Investments	(1,608)	(1,396)	1,515
Net cash used in continuing operations	(216,402)	(344,753)	(480,748)
Net cash provided by discontinued operations	2,234	39,658	98,295
Net cash used in investing activities	(214,168)	(305,095)	(382,453)
Financing activities:			
Issuance of long-term debt	140,812	309,064	345,920
Repayment of long-term debt	(217,394)	(315,647)	(566,498)
Proceeds from issuance of common stock	•	,	21,898
Dividends paid	(150,727)	(147,156)	(142,835)
Redemption of preferred stock	(15,600)	,	,
Repurchase of common stock	(1,684)	,	,
Tax withholding on stock-based compensation	(757)	(323)	,
Net cash used in continuing operations	(245,350)	(154,062)	(341,515)
Net cash provided by (used in) discontinued operations	•	(40,852)	85,785
Net cash used in financing activities	(245,350)	(194,914)	(255,730)
Effect of exchange rate changes on cash and cash equivalents	(1)	4	(225)
Increase (decrease) in cash and cash equivalents	(11,508)	(37,796)	23,424
Cash and cash equivalents - beginning of year	46,107	83,903	60,479
Cash and cash equivalents - end of year	\$ 34,599	\$ 46,107	\$ 83,903

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 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 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, 2017, up to the date of issuance of these consolidated financial statements.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. In accordance with the accounting guidance on accounting for income taxes, entities must account for the effects of the change in tax laws or rates in the period of enactment. In the fourth quarter of 2017, the period of enactment, the Company performed a one-time revaluation of the net deferred tax liabilities to account for the reduction in the corporate tax rate from 35 percent to 21 percent effective January 1, 2018. For more information on the impacts of the TCJA on the year ended December 31, 2017, see Notes 4 and 11. The Company is currently reviewing the components of the TCJA and evaluating the impact on the Company's consolidated financial statements and related disclosures for 2018 and thereafter.

As part of the Company's strategic plan to grow its capital investments while focusing on creating a greater long-term value and reducing the Company's risk by decreasing exposure to commodity prices, the Company completed the sales of substantially all of Fidelity's oil and natural gas assets between October 2015 and April 2016 and Dakota Prairie Refining on June 27, 2016.

The assets and liabilities for the Company's discontinued operations have been classified as held for sale and the results of operations are shown in 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. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded. 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 the Company's 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 \$34.7€million and \$29.2€million at December€31, 2017 and 2016, 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, 2017 and 2016, was \$8.1€million and \$10.5€million, respectively.

Inventories and natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at lower of cost or net realizable value, or cost using the last-in, first-out method. All other inventories are stated at the lower of cost or net realizable 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:

	2017	2016
	(In thousands)	
Aggregates held for resale	\$ 115,268	\$ 115,471
Asphalt oil	30,360	29,103
Natural gas in storage (current)	20,950	25,761
Materials and supplies	18,650	18,372
Merchandise for resale	14,905	16,437
Other	26,450	33,129
Total	\$ 226,583	\$ 238,273

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 deferred charges and other assets - other and was \$49.3€million and \$49.5€million at December€31, 2017 and 2016, 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€5 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:

	2017	2016	2015
	(In thousands)		
Interest capitalized	\$ •	\$,	\$ 4,381
AFUDC - borrowed	\$ 966	\$ 914	\$ 4,907
AFUDC - equity	\$ 909	\$ 565	\$ 7,971

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 deferred credits and other liabilities - other.

Part II

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

	2017	2016	Weighted Average Depreciable Life in Years
(Dollars in thousands, where applicable)			
Regulated:			
Electric:			
Generation	\$ 1,034,765	\$ 1,036,373	39
Distribution	415,543	398,382	44
Transmission	296,941	284,048	57
Construction in progress	117,906	62,212	,
Other	117,109	107,598	15
Natural gas distribution:			
Distribution	1,831,795	1,718,633	47
Construction in progress	19,823	19,934	,
Other	468,227	440,846	18
Pipeline and midstream:			
Transmission	516,932	490,143	53
Gathering	37,837	37,831	20
Storage	45,629	45,350	62
Construction in progress	17,488	16,507	,
Other	41,054	40,873	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	31,678	31,682	19
Construction in progress	17	13	,
Other	9,649	9,800	10
Construction materials and contracting:			
Land	95,745	94,625	,
Buildings and improvements	102,435	102,347	20
Machinery, vehicles and equipment	947,979	930,471	12
Construction in progress	7,750	16,181	,
Aggregate reserves	406,139	405,751	*
Construction services:			
Land	5,216	5,346	,
Buildings and improvements	27,351	26,693	25
Machinery, vehicles and equipment	137,924	132,217	6
Other	6,774	7,105	4
Other:			
Land	2,837	2,837	,
Other	28,286	46,431	19
Less accumulated depreciation, depletion and amortization	2,691,641	2,578,902	
Net property, plant and equipment	\$ 4,079,188	\$ 3,931,327	

* Depleted on the units-of-production method based on recoverable aggregate reserves.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill 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), largely 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 quarter of 2015, the Company recognized an impairment of \$3.0 million (before tax) related to coalbed natural gas gathering assets located in Wyoming where there had been continued decline in natural gas development and production activity 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 5.

No significant impairment losses were recorded in 2016 or 2017, other than those related to the Company's assets held for sale and discontinued operations. For more information regarding these impairments, see Note 2.

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, 2017, 2016 and 2015, there were no significant impairment losses recorded. At December 31, 2017, 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 2017. 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.

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 \$112.7 million and \$117.7 million at December 31, 2017 and 2016, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. 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.

Part II

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:

	2017		2016	
	(In thousands)			
Costs and estimated earnings in excess of billings on uncompleted contracts	\$	109,541	\$	64,558
Billings in excess of costs and estimated earnings on uncompleted contracts	\$	84,123	\$	64,832

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

	2017		2016	
	(In thousands)			
Short-term retainage*	\$	57,134	\$	45,109
Long-term retainage**		1,410		1,506
Total retainage	\$	58,544	\$	46,615

* Expected to be paid within one year or less and included in receivables, net.

** Included in deferred charges and other assets - other.

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€7.

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 \$28.5€million and \$25.6€million at December€31, 2017 and 2016, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were \$14.5€million and \$2.2€million at December€31, 2017 and 2016, respectively, which is included in prepayments and other current assets.

Stock-based compensation

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also performs an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

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 by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. 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.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. 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 nonvested performance share awards. Common stock outstanding includes issued shares less shares held in treasury. Earnings (loss) on common stock 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:

	2017	2016	2015
		(In thousands)	
Weighted average common shares outstanding - basic	195,304	195,299	194,928
Effect of dilutive performance share awards	383	319	58
Weighted average common shares outstanding - diluted	195,687	195,618	194,986
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 long-lived assets and goodwill; 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.

New accounting standards

Recently adopted accounting standards

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. The Company adopted the guidance on January 1, 2017, on a prospective basis. The guidance did not have a material effect on the Company's results of operations, financial position, cash flows or disclosures.

Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance affects the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. The Company adopted the guidance on January 1, 2017. All amendments in the guidance that apply to the Company were adopted on a prospective basis resulting in no adjustments being made to retained earnings. The adoption of the guidance impacted the Consolidated Statement of Income and the Consolidated Balance Sheet in the first quarter of 2017 due to the taxes related to the stock-based compensation award that vested in February 2017 being recognized as income tax expense as compared to a reduction to additional paid-in capital under the previous guidance. Adoption of the guidance also increased the number of shares included in the diluted earnings per share calculation due to the exclusion of tax benefits in the incremental shares calculation. The change in the weighted average common shares outstanding - diluted did not result in a material effect on the earnings per common share - diluted.

Part II

Recently issued accounting standards not yet adopted

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. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was effective for the Company on January 1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

The Company adopted the guidance on January 1, 2018, using the modified retrospective approach. The Company has substantially completed the evaluation of contracts and methods of revenue recognition under the previous accounting guidance and has not identified any material cumulative effect adjustments to be made to retained earnings. In addition, the Company will have expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers in the first quarter of 2018. The Company has reviewed substantially all of its revenue streams to evaluate the impact of this guidance and does not anticipate a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacts certain business processes and controls. As such, the Company has developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant.

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 was effective for the Company on January 1, 2018. The guidance was to be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which should be applied prospectively. The Company continues to evaluate the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures and does not anticipate a material impact.

Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. The Company adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Clarifying the Definition of a Business In January 2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March 2017, the FASB issued guidance to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. The guidance requires the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net benefit costs shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance also allows only the service cost component to be eligible for capitalization. The guidance was effective for the Company on January 1, 2018, including interim periods, on a retrospective basis for all periods presented with the exception of the capitalization of the service cost component which was adopted on a prospective basis.

The Company will reclassify all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income (expense) on the Consolidated Statements of Income for all years presented prior to January 1, 2018, beginning in the first quarter of 2018, with no impact to earnings. The guidance will not have a material impact on the Company's disclosures or cash flows.

Under FERC regulation, all components of net periodic benefit costs are currently eligible for capitalization. The Company's electric and natural gas distribution businesses have elected to continue to defer all components of net periodic benefit costs as regulatory assets or liabilities.

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases with terms of more than 12 months. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. This guidance will be effective for the Company on January 1, 2019, and should be applied using a retrospective approach with early adoption permitted. The Company continues to evaluate the potential impact the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures. The Company is planning to adopt the standard on January 1, 2019, utilizing the practical expedient that allows the Company to not reassess whether an expired or existing contract contains a lease, the classification of leases or initial direct costs.

In January 2018, the FASB issued a practical expedient for land easements under the new lease guidance. The practical expedient permits an entity to elect the option to not evaluate land easements under the new guidance if they existed or expired before the adoption of the new lease guidance and were not previously accounted for as leases under the previous lease guidance. Once an entity adopts the new guidance, the entity should apply the new guidance on a prospective basis to all new or modified land easements. The Company is currently evaluating the impact of the practical expedient.

On January 5, 2018, the FASB issued a proposed accounting standard update to the guidance that would allow an entity the option to adopt the guidance on a modified retrospective basis. Under the modified retrospective approach, an entity would recognize a cumulative effect adjustment of initially applying the guidance to the opening balance of retained earnings in the period of adoption. The Company is monitoring the status of the proposal.

Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step 2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step 1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The guidance will be effective for the Company on January 1, 2020, and should be applied on a prospective basis with early adoption 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.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company is evaluating adoption of the guidance in the first quarter of 2018. At December 31, 2017, the Company had \$7.7 million of stranded tax effects in the accumulated other comprehensive loss balance.

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.

Part II

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.

The after-tax changes in the components of accumulated other comprehensive loss as of December€31, 2017, 2016 and 2015, 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, 2015	\$ (2,667)	\$ (34,257)	\$ (200)	\$ (24)	\$ (37,148)
Other comprehensive income (loss) before reclassifications	,	(1,470)	51	(182)	(1,601)
Amounts reclassified from accumulated other comprehensive loss	367	2,506	,	143	3,016
Net current-period other comprehensive income (loss)	367	1,036	51	(39)	1,415
Balance at December€31, 2016	(2,300)	(33,221)	(149)	(63)	(35,733)
Other comprehensive loss before reclassifications	,	(1,812)	(6)	(139)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	366	1,013	,	120	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	,	(1,143)	,	,	(1,143)
Net current-period other comprehensive income (loss)	366	(1,942)	(6)	(19)	(1,601)
Balance at December€31, 2017	\$ (1,934)	\$ (35,163)	\$ (155)	\$ (82)	\$ (37,334)

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

	2017	2016	Location on Consolidated Statements of Income
(In thousands)			
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Interest rate derivative instruments	\$ (590)	\$ (593)	Interest expense
	224	226	Income taxes
	(366)	(367)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	(1,658)	(3,931)	(a)
	645	1,425	Income taxes
	(1,013)	(2,506)	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	(185)	(220)	Other income
	65	77	Income taxes
	(120)	(143)	
Total reclassifications	\$ (1,499)	\$ (3,016)	

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

Note€2 - Assets Held for Sale and Discontinued Operations

Assets held for sale

The assets of Pronghorn were classified as held for sale in the fourth quarter of 2016. Pronghorn's results of operations for 2016 were included in the pipeline and midstream segment.

On November 21, 2016, WBI Energy Midstream announced it had entered into a purchase and sale agreement to sell its 50 percent non-operating ownership interest in Pronghorn to Andeavor Field Services LLC. The transaction closed on January 1, 2017, which generated approximately \$100 million of proceeds for the Company. The sale of Pronghorn further reduced the Company's risk exposure to commodity prices.

The carrying amounts of the major classes of assets classified as held for sale associated with Pronghorn on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2016	
	(In thousands)	
Assets		
Current assets:		
Prepayments and other current assets	\$	68
Total current assets held for sale		68
Noncurrent assets:		
Net property, plant and equipment		93,424
Goodwill		9,737
Less allowance for impairment of assets held for sale		2,311
Total noncurrent assets held for sale		100,850
Total assets held for sale	\$	100,918

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the fourth quarter of 2016, the fair value assessment was determined using the market approach based on the purchase and sale agreement with Andeavor Field Services LLC. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of \$2.3 million (\$1.4 million after tax) in the quarter ended December 31, 2016. The fair value of Pronghorn's assets have been categorized as Level 3 in the fair value hierarchy. The impairment was recorded in operation and maintenance expense on the Consolidated Statement of Income.

Discontinued operations

The assets and liabilities of the Company's discontinued operations have been classified as held for sale and the results of operations are shown in 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. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet's 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduced the Company's risk by decreasing exposure to commodity prices.

Centennial continues to guarantee certain debt obligations of Dakota Prairie Refining; however, Tesoro has agreed to indemnify Centennial for any losses and litigation expenses arising for the guarantee. For more information related to the guarantee, see Note 17.

Part II

The carrying amounts of the major classes of assets and liabilities classified as held for sale, related to the operations of and activity associated with Dakota Prairie Refining, on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2017		2016
	(In thousands)		
Assets			
Current assets:			
Income taxes receivable	\$ 1,778	\$	13,987
Total current assets held for sale	1,778		13,987
Total assets held for sale	\$ 1,778	(a)	\$ 13,987
Liabilities			
Current liabilities:			
Accounts payable	\$ •	\$	7,425
Total current liabilities held for sale	•		7,425
Noncurrent liabilities:			
Deferred income taxes (b)	37		14
Total noncurrent liabilities held for sale	37		14
Total liabilities held for sale	\$ 37	\$	7,439

(a) On the Company's Consolidated Balance Sheets, these amounts were reclassified to current income taxes payable and are reflected in current liabilities held for sale.

(b) On the Company's Consolidated Balance Sheets, these amounts were reclassified to noncurrent deferred income tax assets and are reflected in noncurrent assets held for sale.

The Company retained certain liabilities of Dakota Prairie Refining which were reflected in current liabilities held for sale on the Consolidated Balance Sheet at December 31, 2016. In the first quarter of 2017, the Company recorded a reversal of a previously accrued liability of \$7.0 million (\$4.3 million after tax) due to the resolution of a legal matter. As of December 31, 2017, Dakota Prairie Refining had not incurred any material exit and disposal costs, and does not expect to incur any material exit and disposal costs.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the market approach based on the sale transaction to Tesoro. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of \$251.9 million (\$156.7 million after tax) in the quarter ended June 30, 2016. The impairment was included in operating expenses from discontinued operations. The fair value of Dakota Prairie Refining's assets have been categorized as Level 3 in the fair value hierarchy.

Fidelity 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. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell substantially all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. The sale of Fidelity was 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 carrying amounts of the major classes of assets and liabilities classified as held for sale, related to the operations of Fidelity, on the Company's Consolidated Balance Sheets at December€31 were as follows:

	2017		2016	
	(In thousands)			
Assets				
Current assets:				
Receivables, net	\$	479	\$	355
Total current assets held for sale		479		355
Noncurrent assets:				
Net property, plant and equipment		1,631		5,507
Deferred income taxes		2,637		91,098
Other		161		161
Less allowance for impairment of assets held for sale		•		938
Total noncurrent assets held for sale		4,429		95,828
Total assets held for sale	\$	4,908	\$	96,183
Liabilities				
Current liabilities:				
Accounts payable	\$	30	\$	141
Taxes payable		10,857		19 (a)
Other accrued liabilities		2,884		2,358
Total current liabilities held for sale		13,771		2,518
Total liabilities held for sale	\$	13,771	\$	2,518

(a) On the Company's Consolidated Balance Sheets, this amount was reclassified to prepayments and other current assets and is reflected in current assets held for sale.

At December€31, 2017 and 2016, the Company's deferred tax assets included in assets held for sale were largely comprised of \$2.6€million and \$89.3€million, respectively, of federal and state net operating loss carryforwards. The Company realized substantially all of the outstanding net operating loss carryforwards in 2017.

The Company had federal income tax net operating loss carryforwards of \$4.4€million and \$297.2€million at December€31, 2017 and 2016, respectively. At December€31, 2017 and 2016, the Company had various state income tax net operating loss carryforwards of \$13.8€million and \$189.1€million, respectively. The federal net operating loss carryforwards expire in 2036 and 2037 if not utilized. The state net operating loss carryforwards are due to expire between 2023 and 2037. It is likely a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances of \$349,000 and \$500,000 have been provided in 2017 and 2016, respectively.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the first quarter of 2016, the fair value assessment was determined using the market approach largely based on a purchase and sale agreement. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of \$1.4 million (\$900,000 after tax) in the first quarter of 2016. In the second quarter of 2016, the fair value assessment was determined using the income and market approaches. The income approach was determined by using the present value of future estimated cash flows. The market approach was based on market transactions of similar properties. The estimated carrying value exceeded the fair value and the Company recorded an impairment of \$900,000 (\$600,000 after tax) in the second quarter of 2016.

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 is 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

Part II

than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement had not been entered into at that time, the fair value was 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 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. 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.

The Company incurred transaction costs of approximately \$300,000 in the first quarter of 2016 and \$2.5 million in 2015. In addition to the 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 \$5.6 million of exit and disposal costs in 2016, and has incurred \$10.5 million of exit and disposal costs to date. The Company does not expect to incur any additional material exit and disposal costs. The exit and disposal costs are associated with severance and other related matters and exclude the office lease expiration discussed in the following paragraph.

Fidelity vacated its office space in Denver, Colorado in 2016. The Company incurred lease payments of approximately \$900,000 in 2016. Lease termination payments of \$3.2 million and \$3.3 million were made during the second quarter of 2016 and fourth quarter of 2015, respectively. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

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.

Fidelity previously held commodity derivatives that were not designated as hedging instruments. The amount of loss recognized in discontinued operations, before tax, was \$18.3 million in the year ended December 31, 2015.

The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations, which includes Dakota Prairie Refining and Fidelity, to the after-tax loss from discontinued operations on the Company's Consolidated Statements of Income for the years ended December 31 were as follows:

	2017	2016	2015
	(In thousands)		
Operating revenues	\$ 465	\$ 123,024	\$ 363,115
Operating expenses	(4,607)	513,813	1,666,941
Operating income (loss)	5,072	(390,789)	(1,303,826)
Other income (expense)	(13)	306	3,149
Interest expense	250	1,753	2,124
Income (loss) from discontinued operations before income taxes	4,809	(392,236)	(1,302,801)
Income taxes*	8,592	(91,882)	(468,721)
Loss from discontinued operations	(3,783)	(300,354)	(834,080)
Loss from discontinued operations attributable to noncontrolling interest	•	(131,691)	(35,256)
Loss from discontinued operations attributable to the Company	\$ (3,783)	\$ (168,663)	\$ (798,824)

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

The pretax income (loss) from discontinued operations attributable to the Company, related to the operations of and activity associated with Dakota Prairie Refining, was \$6.9€million, \$(253.5)€million and \$(31.5)€million for the years ended December€31, 2017, 2016 and 2015, respectively.

Note€3 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December€31, 2017, were as follows:

	Balance at January€1, 2017	Goodwill Acquired During the Year	Balance at December€31, 2017
(In thousands)			
Natural gas distribution	\$ 345,736	\$,	\$ 345,736
Construction materials and contracting	176,290	,	176,290
Construction services	109,765	,	109,765
Total	\$ 631,791	\$,	\$ 631,791

The changes in the carrying amount of goodwill for the year ended December€31, 2016, were as follows:

	Balance at January€1, 2016 *	Goodwill Acquired During the Year	Less Held for Sale	Balance at December€31, 2016
(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	6,324	,	109,765
Total	\$ 635,204	\$ 6,324	\$ 9,737	\$ 631,791

* 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:

	2017	2016
(In thousands)		
Customer relationships	\$ 15,248	\$ 17,145
Less accumulated amortization	13,382	13,917
	1,866	3,228
Noncompete agreements	2,430	2,430
Less accumulated amortization	1,805	1,658
	625	772
Other	6,990	7,768
Less accumulated amortization	5,644	5,843
	1,346	1,925
Total	\$ 3,837	\$ 5,925

Amortization expense for amortizable intangible assets for the years ended December€31, 2017, 2016 and 2015, was \$2.0€million, \$2.5€million and \$2.5€million, respectively. Estimated amortization expense for intangible assets is \$1.3€million in 2018, \$1.0€million in 2019, \$500,000 in 2020, \$300,000 in 2021, \$200,000 in 2022 and \$500,000 thereafter.

Part II

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 *	2017	2016
(In thousands)			
Regulatory assets:			
Pension and postretirement benefits (a)	(e) \$	163,896	\$ 176,025
Taxes recoverable from customers (a)	Over plant lives	12,073	28,278
Manufactured gas plant sites remediation (a)	-	18,213	18,259
Asset retirement obligations (a)	Over plant lives	56,078	42,580
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	14,465	2,242
Long-term debt refinancing costs (a)	Up to 20 years	5,563	6,248
Costs related to identifying generation development (a)	Up to 9 years	2,960	3,407
Other (a) (b)	Up to 20 years	27,715	30,281
Total regulatory assets		300,963	307,320
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		176,190	176,972
Taxes refundable to customers (c)		279,668	11,010
Pension and postretirement benefits (c)		11,056	9,099
Natural gas costs refundable through rate adjustments (d)		28,514	25,580
Other (c) (d)		23,870	19,191
Total regulatory liabilities		519,298	241,852
Net regulatory position	\$	(218,335)	\$ 65,468

* 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 deferred credits and other liabilities - other 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, 2017 and 2016, approximately \$269.1 million and \$255.4 million, respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. The revaluation of the Company's regulatory deferred tax assets and liabilities are being deferred as the Company works with the various regulators on a plan for amounts expected to be returned to customers, as discussed in Note 16. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of \$15.5 million in taxes recoverable from customers and an increase of \$270.0 million in taxes refundable to customers. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

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 - 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 \$77.4 million and \$70.9 million at December 31, 2017 and 2016, respectively, were classified as investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2017, 2016 and 2015, were \$9.3 million, \$3.4 million and

\$1.7€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, 2017	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	\$ 10,342	\$ 4	\$ 129	10,217
U.S. Treasury securities	205	,	1	204
Total	\$ 10,547	\$ 4	\$ 130	10,421

December€31, 2016	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	\$ 10,546	\$ 8	\$ 105	10,449
Total	\$ 10,546	\$ 8	\$ 105	10,449

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.

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.

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, 2017 and 2016, there were no transfers between Levels€1 and 2.

Part II

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

	Fair Value Measurements at December 31, 2017, Using			Balance at December 31, 2017
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	(In thousands)			
Assets:				
Money market funds	\$, \$	6,965 \$, \$	6,965
Insurance contract*	,	77,388	,	77,388
Available-for-sale securities:				
Mortgage-backed securities	,	10,217	,	10,217
U.S. Treasury securities	,	204	,	204
Total assets measured at fair value	\$, \$	94,774 \$, \$	94,774

* The insurance contract invests approximately 49 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 14 percent in common stock of mid-cap companies, 11 percent in common stock of small-cap companies, 2 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at December 31, 2016, Using			Balance at December 31, 2016
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	(In thousands)			
Assets:				
Money market funds	\$, \$	1,602 \$, \$	1,602
Insurance contract*	,	70,921	,	70,921
Available-for-sale securities:				
Mortgage-backed securities	,	10,449	,	10,449
Total assets measured at fair value	\$, \$	82,972 \$, \$	82,972

* The insurance contract invests approximately 52 percent in fixed-income investments, 22 percent in common stock of large-cap companies, 13 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 1 percent in target date investments and 2 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 quarter of 2015, coalbed 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 these Level€3 nonrecurring fair value measurements, 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:

	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	\$ 1,714,853	\$ 1,826,256	\$ 1,790,159	\$ 1,841,885

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

Note€6 - 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, 2017	Amount Outstanding€at December€31, €2016	Letters of Credit at December€31, 2017	Expiration Date
(In millions)						
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a) \$ 175.0	\$ 73.8 (b)	\$ 111.0 (b)	\$,	5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement	\$ 75.0 (c)	\$ 17.3	\$,	\$ 2.2 (d)	4/24/20
Intermountain Gas Company	Revolving credit agreement	\$ 85.0 (e)	\$ 40.0	\$ 20.9	\$,	4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f) \$ 500.0	\$ 14.6 (b)	\$ 151.0 (b)	\$,	9/23/21

(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 revolving credit agreement.

(b) Amount outstanding under commercial paper program.

(c) Certain provisions allow for increased borrowings, up to a maximum of \$100.0€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 \$110.0€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 \$600.0€million). There were no amounts outstanding under the revolving 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.

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.

Part II

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.

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.

On April 25, 2017, Cascade amended its revolving credit agreement to increase the borrowing limit from \$50.0 million to \$75.0 million and extend the termination date from July 9, 2018 to April 24, 2020. 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.

On April 25, 2017, Intermountain amended its revolving credit agreement to increase the borrowing limit from \$65.0 million to \$85.0 million and extend the termination date from July 13, 2018 to April 24, 2020. 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 restricted payments, restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

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

WBI Energy Transmission, Inc. WBI Energy Transmission has a \$200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had \$100.0 million of notes outstanding at December 31, 2017, which reduced the remaining capacity under this uncommitted private shelf agreement to \$100.0 million. 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. On December 22, 2017, WBI Energy Transmission contracted to issue an additional \$40.0 million under the private shelf agreement at an interest rate of 4.18 percent on June 15, 2018.

Long-term Debt Outstanding Long-term debt outstanding was as follows:

	Weighted Average Interest Rate at December 31, 2017	December 31, 2017	December 31, 2016
(In thousands)			
Senior Notes due on dates ranging from June 19, 2018 to January 15, 2055	4.71%	\$ 1,499,916	\$ 1,437,831
Commercial paper supported by revolving credit agreements	1.72%	88,350	262,000
Medium-Term Notes due on dates ranging from September 1, 2020 to March 16, 2029	6.68%	50,000	50,000
Other notes due on dates ranging from July 1, 2019 to November 30, 2038	5.24%	24,982	24,471
Credit agreements due on April 24, 2020	3.71%	57,300	21,793
Less unamortized debt issuance costs		5,694	5,832
Less discount		1	104
Total long-term debt		1,714,853	1,790,159
Less current maturities		148,499	43,598
Net long-term debt		\$ 1,566,354	\$ 1,746,561

Schedule of Debt Maturities Long-term debt maturities, which excludes unamortized debt issuance costs and discount, for the five years and thereafter following December 31, 2017, were as follows:

	2018	2019	2020	2021	2022	Thereafter
(In thousands)						
Long-term debt maturities	\$ 148,499	\$ 125,504	\$ 73,012	\$ 15,312	\$ 147,214	\$ 1,211,007

Note 7 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, natural gas transmission lines, storage facilities, 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 deferred credits and other liabilities - other on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

	2017	2016
(In thousands)		
Balance at beginning of year	\$ 314,970	\$ 242,224
Liabilities incurred	15,110	15,114
Liabilities settled	(4,981)	(4,338)
Accretion expense*	16,839	13,918
Revisions in estimates	31	48,052
Balance at end of year	\$ 341,969	\$ 314,970

* Includes \$15.6 million and \$12.7 million in 2017 and 2016, respectively, related to regulatory assets.

The 2016 revisions in estimates consist principally of updated asset retirement obligation costs associated with natural gas transmission lines and storage facilities at the pipeline and midstream segment.

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. For more information on the Company's regulatory assets and liabilities, see Note 4.

Part II

Note 8 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2017	2016
	(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
4.70% Series - 50,000 shares		• 5,000
Total preferred stocks	\$	• \$ 15,000

For the years 2016 and 2015, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were \$4.50 and \$4.70 per share, respectively. On April 1, 2017, the Company redeemed all outstanding 4.50% Series and 4.70% Series preferred stocks at \$105 per share and \$102 per share, respectively, for a repurchase price of approximately \$15.6 million and \$300,000 of redeemable preferred stock classified as long-term debt.

Note 9 - Common Stock

For the years 2017, 2016 and 2015, dividends declared on common stock were \$.7750, \$.7550 and \$.7350 per common share, respectively.

The Stock Purchase Plan provided 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 provides participants the option to invest in the Company's common stock. From January 2015 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, purchased shares of authorized but unissued common stock from the Company. From September 2015 through December 2017, the K-Plan purchased shares of common stock on the open market. At December 31, 2017, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From September 2015 through December 4, 2016, the Stock Purchase Plan purchased shares of common stock on the open market. On December 5, 2016, the Stock Purchase Plan was terminated and all remaining shares reserved for original issuance under the plan were de-registered.

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 declare or pay distributions if as of the last day of any fiscal quarter the ratio of Centennial's average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial's Consolidated EBITDA does not exceed 3 to 1; and after giving effect to such distribution, all distributions made during the 12-month period ending on the last day of the fiscal quarter in which such distribution is made will not exceed the remainder of Centennial's Consolidated EBITDA minus Centennial's capital expenditures less the net cash proceeds from all sales of capital assets from continuing operations, for the immediately preceding 12-month period. Intermountain has regulatory limitations on the amount of dividends it can pay. Based on these limitations, approximately \$1.3 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2017. 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 \$384 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, 2017. 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 10 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2017, there were 5.1 million remaining shares available to grant under these plans. The Company generally purchases shares on the open market for non-employee director stock awards. The Company purchased shares on the open market for the employee performance shares that vested in 2017. The Company anticipates future employee performance share awards will continue to be satisfied by purchasing shares on the open market.

Total stock-based compensation expense (after tax) was \$2.7 million, \$3.3 million and \$2.9 million in 2017, 2016 and 2015, respectively.

As of December 31, 2017, total remaining unrecognized compensation expense related to stock-based compensation was approximately \$4.8 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan. There were 40,572 shares with a fair value of \$1.1 million, 37,218 shares with a fair value of \$1.1 million and 58,181 shares with a fair value of \$1.1 million issued under these plans during the years ended December 31, 2017, 2016 and 2015, 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, 2017, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2016	2016-2018	258,825
March 2016	2016-2018	2,151
February 2017	2017-2019	164,558

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 2017, 2016 and 2015 were:

	2017		2016		2015	
Weighted average grant-date fair value	\$24.31		\$14.60		\$18.98	
Blended volatility range	22.70% • 25.56%	29.25% ..	32.51%	22.86% ..	24.61%	
Risk-free interest rate range	.69% • 1.61%	.47% ..	.92%	.05% ..	1.07%	
Weighted average discounted dividends per share	\$1.70		\$1.56		\$1.57	

The fair value of the performance shares that vested during the years ended December 31, 2017 and 2016, was \$9.6 million and \$953,000, respectively. There were no performance shares that vested in 2015.

A summary of the status of the performance share awards for the year ended December 31, 2017, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	664,188	\$ 21.47
Granted	203,646	24.31
Additional performance shares earned	81,643	19.22
Less:		
Vested	360,319	24.88
Forfeited	163,624	24.46
Nonvested at end of period	425,534	\$ 18.35

Part II

Note 11 - Income Taxes

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

	2017	2016	2015
	(In thousands)		
United States	\$ 350,064	\$ 326,252	\$ 248,379
Foreign	(37)	(24)	(1,326)
Income before income taxes from continuing operations	\$ 350,027	\$ 326,228	\$ 247,053

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

	2017	2016	2015
	(In thousands)		
Current:			
Federal	\$ 74,272	\$ 81,989	\$ 85,897
State	16,192	13,190	10,093
Foreign	•	2	30
	90,464	95,181	96,020
Deferred:			
Income taxes:			
Federal	(24,497)	(2,102)	(19,632)
State	(864)	1,184	(5,304)
Investment tax credit - net	(62)	(1,131)	(420)
	(25,423)	(2,049)	(25,356)
Total income tax expense	\$ 65,041	\$ 93,132	\$ 70,664

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax benefit from continuing operations of \$39.5 million on the Consolidated Statements of Income for the year ended December 31, 2017. Included in the tax benefit from continuing operations was income tax expense of \$7.7 million related to amounts in accumulated other comprehensive loss and \$1.0 million related to the Company's assets held for sale.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators on a plan for amounts expected to be returned to customers, as discussed in Notes 4 and 16. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of \$285.5 million in the fourth quarter of 2017. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

The changes included in the TCJA are broad and complex. While the Company was able to make reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities, it may be affected by other analyses related to the TCJA, including, but not limited to, the state tax effect of adjustments to federal temporary differences and the calculation of deemed repatriation of deferred foreign income. The final transition impacts of the TCJA may differ from amounts disclosed, possibly materially, due to, among other things, changes in interpretations, legislative action to address questions, changes in accounting standards for income taxes or related interpretations, or updates or changes to estimates the Company has utilized to calculate the transition impacts. The SEC has issued rules that would allow for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company currently anticipates finalizing and recording any resulting adjustments by December 31, 2018, which will be included in income from continuing operations.

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

	2017	2016
	(In thousands)	
Deferred tax assets:		
Postretirement	\$ 55,736	\$ 87,872
Compensation-related	16,298	44,995
Alternative minimum tax credit carryforward	37,683	29,338
Federal renewable energy credit	19,367	16,944
Customer advances	8,712	13,524
Legal and environmental contingencies	7,363	9,895
Asset retirement obligations	6,380	8,867
Other	35,738	46,957
Total deferred tax assets	187,277	258,392
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	429,577	774,838
Postretirement	43,505	70,670
Intangible asset amortization	16,979	26,413
Other	32,591	45,580
Total deferred tax liabilities	522,652	917,501
Valuation allowance	11,896	9,117
Net deferred income tax liability	\$ 347,271	\$ 668,226

As of December€31, 2017 and 2016, the Company had various state income tax net operating loss carryforwards of \$130.1€million and \$114.7€million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of \$52.5€million and \$43.3€million, respectively. Included in the state credits are various regulatory investment tax credits of approximately \$28.0€million and \$20.7€million at December€31, 2017 and 2016, respectively. The federal income tax credit carryforwards expire in 2036 and 2037 if not utilized and state income tax credit carryforwards are due to expire between 2018 and 2045. 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 are refundable. 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, 2016, to December€31, 2017, to deferred income tax benefit:

	2017
	(In thousands)
Change in net deferred income tax liability from the preceding table	\$ (320,955)
Deferred taxes associated with other comprehensive loss	1,182
Deferred taxes associated with TCJA enactment for regulated activities	285,520
Other	8,830
Deferred income tax benefit for the period	\$ (25,423)

Part II

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,	2017		2016		2015	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	\$ 122,509	35.0	\$ 114,179	35.0	\$ 86,468	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	10,724	3.1	9,027	2.8	8,208	3.3
Federal renewable energy credit	(13,958)	(4.0)	(13,544)	(4.2)	(3,400)	(1.4)
Tax compliance and uncertain tax positions	(643)	(.2)	(3,028)	(.9)	(2,607)	(1.0)
Domestic production deduction	(6,849)	(2.0)	(6,251)	(1.9)	(6,842)	(2.8)
TCJA revaluation	(47,242)	(13.5)	,	,	,	,
TCJA revaluation related to accumulated other comprehensive loss balance	7,735	2.2	,	,	,	,
Other	(7,235)	(2.0)	(7,251)	(2.3)	(11,163)	(4.5)
Total income tax expense	\$ 65,041	18.6	\$ 93,132	28.5	\$ 70,664	28.6

Included in the TCJA is the deemed repatriation transition tax which is a one-time transition tax on previously untaxed accumulated earnings and profits of certain foreign operations that is payable over 8 years. At December 31, 2017, the Company's liability for the deemed repatriation transition tax was \$447,000. Historically, deferred income taxes were accrued with respect to the Company's foreign operations.

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 2014. With few exceptions, as of December 31, 2017, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2013.

The Company had no unrecognized tax benefits (excluding interest) for the years ended December 31, 2017, 2016 and 2015.

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2017, 2016 and 2015, the Company recognized approximately \$(99,000), \$(92,000) and \$122,000, respectively, of interest (income) expense in income tax expense. At December 31, 2017 and 2016, the Company had accrued receivables of approximately \$46,000 and \$54,000, respectively, for interest.

Note 12 - Cash Flow Information

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

	2017	2016	2015
	(In thousands)		
Interest, net*	\$ 79,638	\$ 87,920	\$ 88,775
Income taxes paid, net**	\$ 112,137	\$ 105,908	\$ 61,405

* Capitalized interest and AFUDC - borrowed was \$966,000, \$914,000 and \$9.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

** Income taxes paid, net of discontinued operations, were \$9.7 million, \$1.3 million and \$2.4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Noncash investing transactions at December 31 were as follows:

	2017	2016	2015
	(In thousands)		
Property, plant and equipment additions in accounts payable	\$ 29,263	\$ 22,712	\$ 39,754

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 and gathering services through regulated and nonregulated pipeline systems 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. For information on the Company's natural gas and oil gathering and processing facility sold on January 1, 2017, see Note 2.

The construction materials and contracting segment operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix; and supply ready-mixed concrete. This segment focuses on vertical integration of construction services to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. 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. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment provides inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This business also designs, constructs and maintains renewable energy projects. These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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 self-insured layers of the insured companies' general liability, automobile liability, pollution liability and other coverages. Centennial Capital also owns certain real and personal property. The Other category also includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to the refining business and Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in Brazil.

Discontinued operations includes the results and supporting activities of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. Dakota Prairie Refining refined crude oil and produced and sold diesel fuel, naphtha, ATBs and other by-products of the production process. In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining. 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. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell substantially all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. For more information on discontinued operations, see Note 2.

Part II

The information below follows the same accounting policies as described in Note 1. Information on the Company's segments as of December 31 and for the years then ended was as follows:

	2017	2016	2015
	(In thousands)		
External operating revenues:			
Regulated operations:			
Electric	\$ 342,805	\$ 322,356	\$ 280,615
Natural gas distribution	848,388	766,115	817,419
Pipeline and midstream	53,566	52,983	51,004
	1,244,759	1,141,454	1,149,038
Nonregulated operations:			
Pipeline and midstream	19,602	39,602	54,281
Construction materials and contracting	1,811,964	1,873,696	1,901,530
Construction services	1,366,317	1,072,663	907,767
Other	709	1,413	1,436
	3,198,592	2,987,374	2,865,014
Total external operating revenues	\$ 4,443,351	\$ 4,128,828	\$ 4,014,052
Intersegment operating revenues:			
Regulated operations:			
Electric	\$ •	\$,	\$,
Natural gas distribution	•	,	,
Pipeline and midstream	48,867	48,794	49,065
	48,867	48,794	49,065
Nonregulated operations:			
Pipeline and midstream	178	223	554
Construction materials and contracting	565	574	2,752
Construction services	1,285	609	18,660
Other	7,165	7,230	7,755
	9,193	8,636	29,721
Intersegment eliminations	(58,060)	(57,430)	(78,786)
Total intersegment operating revenues	\$ •	\$,	\$,
Depreciation, depletion and amortization:			
Electric	\$ 47,715	\$ 50,220	\$ 37,583
Natural gas distribution	69,381	65,426	64,756
Pipeline and midstream	16,788	24,885	27,981
Construction materials and contracting	55,862	58,413	65,937
Construction services	15,739	15,307	13,420
Other	2,001	2,067	2,070
Total depreciation, depletion and amortization	\$ 207,486	\$ 216,318	\$ 211,747
Interest expense:			
Electric	\$ 25,377	\$ 24,982	\$ 17,421
Natural gas distribution	31,234	30,405	29,471
Pipeline and midstream	4,990	7,903	9,895
Construction materials and contracting	14,778	15,265	15,183
Construction services	3,742	4,059	3,959
Other	3,564	5,854	15,853
Intersegment eliminations	(897)	(620)	(603)
Total interest expense	\$ 82,788	\$ 87,848	\$ 91,179

Part II

	2017	2016	2015
	(In thousands)		
Income taxes:			
Electric	\$ 7,699	\$ 1,449	\$ 11,523
Natural gas distribution	22,756	9,181	11,377
Pipeline and midstream	12,281	12,408	7,505
Construction materials and contracting	5,405	60,625	41,619
Construction services	25,558	17,748	16,432
Other	(1,809)	(2,028)	(9,834)
Intersegment eliminations	(6,849)	(6,251)	(7,958)
Total income taxes	\$ 65,041	\$ 93,132	\$ 70,664
Earnings (loss) on common stock:			
Regulated operations:			
Electric	\$ 49,366	\$ 42,222	\$ 35,914
Natural gas distribution	32,225	27,102	23,607
Pipeline and midstream	20,620	22,060	20,680
	102,211	91,384	80,201
Nonregulated operations:			
Pipeline and midstream	(127)	1,375	(7,430)
Construction materials and contracting	123,398	102,687	89,096
Construction services	53,306	33,945	23,762
Other	(1,422)	(3,231)	(14,941)
	175,155	134,776	90,487
Intersegment eliminations (a)	6,849	6,251	5,016
Earnings on common stock before loss from discontinued operations	284,215	232,411	175,704
Loss from discontinued operations, net of tax (a)	(3,783)	(300,354)	(834,080)
Loss from discontinued operations attributable to noncontrolling interest	•	(131,691)	(35,256)
Total earnings (loss) on common stock	\$ 280,432	\$ 63,748	\$ (623,120)
Capital expenditures:			
Electric	\$ 109,107	\$ 111,134	\$ 332,876
Natural gas distribution	146,981	126,272	130,793
Pipeline and midstream	31,054	34,467	18,315
Construction materials and contracting	44,302	37,845	48,126
Construction services	18,630	60,344	38,269
Other	1,850	2,358	3,755
Total capital expenditures (b)	\$ 351,924	\$ 372,420	\$ 572,134
Assets:			
Electric (c)	\$ 1,470,922	\$ 1,406,694	\$ 1,325,858
Natural gas distribution (c)	2,201,081	2,099,296	2,038,433
Pipeline and midstream	566,295	550,615	591,651
Construction materials and contracting	1,238,696	1,220,459	1,261,963
Construction services	591,382	513,093	442,845
Other (d)	261,419	283,255	287,940
Assets held for sale	4,871	211,055	616,464
Total assets	\$ 6,334,666	\$ 6,284,467	\$ 6,565,154

Part II

	2017	2016	2015
	(In thousands)		
Property, plant and equipment:			
Electric (c)	\$ 1,982,264	\$ 1,888,613	\$ 1,786,148
Natural gas distribution (c)	2,319,845	2,179,413	2,076,581
Pipeline and midstream	700,284	672,199	758,729
Construction materials and contracting	1,560,048	1,549,375	1,553,428
Construction services	177,265	171,361	163,279
Other	31,123	49,268	49,537
Less accumulated depreciation, depletion and amortization	2,691,641	2,578,902	2,489,322
Net property, plant and equipment	\$ 4,079,188	\$ 3,931,327	\$ 3,898,380

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

(b) Capital expenditures for 2017, 2016 and 2015 include noncash capital expenditure-related accounts payable and AFUDC, totaling \$10.5€million, \$(15.8)€million and \$35.3€million, respectively.

(c) Includes allocations of common utility property.

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

Note 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified 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. As of June 30, 2015, all of the Company's defined pension plans were frozen. These employees were 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, 2017 and 2016, and amounts recognized in the Consolidated Balance Sheets at December€31, 2017 and 2016, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	\$ 436,307	\$ 442,960	\$ 89,304	\$ 92,734
Service cost	•	,	1,508	1,647
Interest cost	16,207	17,218	3,265	3,688
Plan participants' contributions	•	,	1,368	1,405
Actuarial (gain) loss	19,119	1,882	1,781	(3,872)
Benefits paid	(25,710)	(25,753)	(6,020)	(6,298)
Benefit obligation at end of year	445,923	436,307	91,206	89,304
Change in net plan assets:				
Fair value of plan assets at beginning of year	333,509	332,667	82,846	82,593
Actual gain on plan assets	45,473	26,595	9,612	4,184
Employer contribution	1,112	,	933	962
Plan participants' contributions	•	,	1,368	1,405
Benefits paid	(25,710)	(25,753)	(6,020)	(6,298)
Fair value of net plan assets at end of year	354,384	333,509	88,739	82,846
Funded status - under	\$ (91,539)	\$ (102,798)	\$ (2,467)	\$ (6,458)
Amounts recognized in the Consolidated Balance Sheets at December€31:				
Deferred charges and other assets - other	\$ •	\$,	\$ 19,114	\$ 13,131
Other accrued liabilities	•	,	612	538
Deferred credits and other liabilities - other	91,539	102,798	20,969	19,051
Benefit obligation liabilities - net amount recognized	\$ (91,539)	\$ (102,798)	\$ (2,467)	\$ (6,458)
Amounts recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities) consist of:				
Actuarial loss	\$ 186,486	\$ 198,668	\$ 13,423	\$ 17,470
Prior service credit	•	,	(11,632)	(13,003)
Total	\$ 186,486	\$ 198,668	\$ 1,791	\$ 4,467

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:

	2017		2016	
	(In thousands)			
Projected benefit obligation	\$	445,923	\$	436,307
Accumulated benefit obligation	\$	445,923	\$	436,307
Fair value of plan assets	\$	354,384	\$	333,509

Part II

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		
	2017	2016	2015	2017	2016	2015
	(In thousands)					
Components of net periodic benefit cost (credit):						
Service cost	\$ •	\$,	\$ 86	\$ 1,508	\$ 1,647	\$ 1,816
Interest cost	16,207	17,218	17,141	3,265	3,688	3,607
Expected return on assets	(20,528)	(20,924)	(22,254)	(4,641)	(4,533)	(4,795)
Amortization of prior service cost (credit)	•	,	36	(1,371)	(1,371)	(1,371)
Recognized net actuarial loss	6,355	6,215	7,016	857	1,491	1,960
Curtailment loss	•	,	258	•	,	,
Net periodic benefit cost (credit), including amount capitalized	2,034	2,509	2,283	(382)	922	1,217
Less amount capitalized	310	381	316	(370)	(52)	120
Net periodic benefit cost (credit)	1,724	2,128	1,967	(12)	974	1,097
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive (income) loss or regulatory assets (liabilities):						
Net (gain) loss	(5,827)	(3,789)	8,257	(3,190)	(3,523)	(1,336)
Amortization of actuarial loss	(6,355)	(6,215)	(7,016)	(857)	(1,491)	(1,960)
Amortization of prior service (cost) credit	•	,	(294)	1,371	1,371	1,371
Total recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities)	(12,182)	(10,004)	947	(2,676)	(3,643)	(1,925)
Total recognized in net periodic benefit cost (credit), accumulated other comprehensive (income) loss and regulatory assets (liabilities)	\$ (10,458)	\$ (7,876)	\$ 2,914	\$ (2,688)	\$ (2,669)	\$ (828)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2018 is \$7.0€million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2018 are \$800,000 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	
	2017	2016	2017	2016
Discount rate	3.38%	3.83%	3.41%	3.86%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%
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	
	2017	2016	2017	2016
Discount rate	3.83%	4.00%	3.86%	4.06%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%
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, 2017, 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 20€percent to 25€percent equity securities and 75€percent to 80€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:

	2017		2016	
Health care trend rate assumed for next year	7.5%	8.5%	8.6%	10.7%
Health care cost trend rate - ultimate		4.5%		4.5%
Year in which ultimate trend rate achieved		2024		2024

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, 2017:

	1 Percentage Point Increase		1 Percentage Point Decrease	
	(In thousands)			
Effect on total of service and interest cost components	\$	306	\$	(247)
Effect on postretirement benefit obligation	\$	5,433	\$	(4,551)

Outside investment managers manage the Company's pension and postretirement assets. 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.

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.

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.

Part II

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, 2017 and 2016, 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, 2017, Using			Balance at December 31, 2017
	Quoted Prices in Active Markets for Identical Assets €(Level 1)	Significant Other Observable Inputs €(Level 2)	Significant Unobservable Inputs €(Level 3)	
	(In thousands)			
Assets:				
Cash equivalents	\$	\$	3,814	\$ 3,814
Equity securities:				
U.S. companies	13,345	,	,	13,345
International companies	1,766	,	,	1,766
Collective and mutual funds*	171,822	67,749	,	239,571
Corporate bonds	,	74,956	,	74,956
Municipal bonds	,	16,839	,	16,839
U.S. Government securities	1,038	,	,	1,038
Total assets measured at fair value	\$ 187,971	\$ 163,358	\$	\$ 351,329

* Collective and mutual funds invest approximately 31 percent in common stock of international companies, 28 percent in corporate bonds, 19 percent in common stock of large-cap U.S. companies, 7 percent in cash equivalents, 1 percent in U.S. Government securities and 14 percent in other investments.

	Fair Value Measurements at December 31, 2016, Using			Balance at December 31, 2016
	Quoted Prices in Active Markets for Identical Assets €(Level 1)	Significant Other Observable Inputs €(Level 2)	Significant Unobservable Inputs €(Level 3)	
	(In thousands)			
Assets:				
Cash equivalents	\$	\$	6,347	\$ 6,347
Equity securities:				
U.S. companies	11,348	,	,	11,348
International companies	1,584	,	,	1,584
Collective and mutual funds*	162,055	64,052	,	226,107
Corporate bonds	,	68,677	,	68,677
Municipal bonds	,	11,002	,	11,002
U.S. Government securities	4,352	2,044	,	6,396
Total assets measured at fair value	\$ 179,339	\$ 152,122	\$	\$ 331,461

* Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in corporate bonds, 20 percent in common stock of large-cap U.S. companies, 8 percent in cash equivalents, 7 percent in U.S. Government securities and 15 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.

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, 2017 and 2016, 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, 2017, Using			Balance at December€31, 2017
	Quoted Prices in Active Markets for Identical Assets €(Level€1)	Significant Other Observable Inputs €(Level€2)	Significant Unobservable Inputs €(Level€3)	
	(In thousands)			
Assets:				
Cash equivalents	\$,	\$ 4,815	\$ 4,815
Equity securities:				
U.S. companies	2,316	,	,	2,316
International companies	4	,	,	4
Insurance contract*	3	81,601	,	81,604
Total assets measured at fair value	\$ 2,323	\$ 86,416	\$	\$ 88,739

* The insurance contract invests approximately 38€percent in corporate bonds, 23€percent in common stock of large-cap U.S. companies, 21€percent in U.S. Government securities, 9€percent in mortgage-backed securities and 9€percent in other investments.

	Fair Value Measurements at December€31, 2016, Using			Balance at December€31, 2016
	Quoted Prices in Active Markets for Identical Assets €(Level€1)	Significant Other Observable Inputs €(Level€2)	Significant Unobservable Inputs €(Level€3)	
	(In thousands)			
Assets:				
Cash equivalents	\$,	\$ 250	\$ 250
Equity securities:				
U.S. companies	2,328	,	,	2,328
International companies	5	,	,	5
Insurance contract*	,	80,263	,	80,263
Total assets measured at fair value	\$ 2,333	\$ 80,513	\$	\$ 82,846

* The insurance contract invests approximately 38€percent in corporate bonds, 25€percent in common stock of large-cap U.S. companies, 20 percent in U.S. Government securities, 9€percent in mortgage-backed securities and 8€percent in other investments.

The Company expects to contribute approximately \$17.7€million to its defined benefit pension plans and approximately \$800,000 to its postretirement benefit plans in 2018.

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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)		
2018	\$ 25,111	\$ 5,490	\$ 152
2019	25,280	5,525	147
2020	25,587	5,396	141
2021	25,866	5,391	132
2022	26,185	5,470	123
2023 - 2027	130,994	27,106	454

Nonqualified benefit plans

In addition to the qualified defined pension benefit plans 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, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was \$4.7 million, \$1.8 million and \$7.1 million in 2017, 2016 and 2015, respectively, which reflects a curtailment gain of \$3.3 million in the first quarter of 2016. The total projected benefit obligation for these plans was \$102.5 million and \$101.8 million at December 31, 2017 and 2016, respectively. The accumulated benefit obligation for these plans was \$102.5 million and \$101.8 million at December 31, 2017 and 2016, respectively. A weighted average discount rate of 3.20 percent and 3.56 percent at December 31, 2017 and 2016, respectively, was used to determine the benefit obligation. No rate of compensation increase was used to determine the benefit obligation at December 31, 2017 and 2016, due to the plans being frozen. A discount rate of 3.56 percent and 3.77 percent for the years ended December 31, 2017 and 2016, respectively, and a rate of compensation increase of 4.00 percent for the year ended 2016 was used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate \$7.1 million in 2018; \$7.3 million in 2019; \$7.7 million in 2020; \$7.7 million in 2021; \$7.0 million in 2022 and \$37.0 million for the years 2023 through 2027.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2017, 2016 and 2015 were \$736,000, \$395,000 and \$207,000, respectively.

The Company had investments of \$122.9 million and \$111.0 million at December 31, 2017 and 2016, respectively, consisting of equity securities of \$68.3 million and \$62.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of \$36.5 million and \$35.5 million, respectively, and other investments of \$18.1 million and \$13.0 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 \$41.2 million in 2017, \$40.9 million in 2016 and \$36.8 million in 2015.

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:

- f Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
- f If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- f 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 2017 and 2016 is for the plan's year-end at December 31, 2016, and December 31, 2015, 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		FIP/RP Status Pending/Implemented	Contributions			Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
		2017	2016		2017	2016	2015		
(In thousands)									
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2017	Yellow as of 6/30/2016	Implemented	\$ 690	\$ 766	\$ 917	No	12/31/2018
Edison Pension Plan	93-6061681-001	Green	Green	No	12,725	6,242	5,517	No	6/30/2019
IBEW Local No. 82 Pension Plan	31-6127268-001	Green as of 6/30/2017	Green as of 6/30/2016	No	1,757	2,560	2,252	No	12/1/2019
IBEW Local 212 Pension Trust Fund	31-6127280-001	Green as of 4/30/2016	Yellow as of 4/30/2015	No	1,312	1,146	937	No	6/2/2019
IBEW Local No. 357 Pension Plan A	88-6023284-001	Green	Green	No	3,286	3,016	1,896	No	5/31/2018
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2017	Red as of 2/29/2016	Implemented	2,254	773	745	No	9/2/2018
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2017	Green as of 5/31/2016	No	1,156	1,221	1,169	No	9/30/2019
Minnesota Teamsters Construction Division Pension Fund	41-6187751-001	Green as of 11/30/2016	Green as of 11/30/2015	No	826	690	737	No	4/30/2019
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red	Red	Implemented	718	775	677	No	7/31/2018-3/31/2021
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	8,891	6,366	5,271	No	10/31/2017-3/31/2021
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Yellow	Red	Implemented	1,016	1,087	714	No	6/30/2018
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	48	50	26	No	1/31/2019
Other funds					22,066	19,835	18,254		
Total contributions					\$ 56,745	\$ 44,527	\$ 39,112		

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	2016 and 2015
IBEW Local 82 Pension Plan	2016 and 2015
IBEW Local 124 Pension Trust Fund	2016 and 2015
IBEW Local 212 Pension Trust Fund	2016 and 2015
IBEW Local 357 Pension Plan A	2016 and 2015
IBEW Local 648 Pension Plan	2016 and 2015
Idaho Plumbers and Pipefitters Pension Plan	2016 and 2015
International Union of Operating Engineers Local 701 Pension Trust Fund	2016 and 2015
Minnesota Teamsters Construction Division Pension Fund	2016 and 2015
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2016 and 2015

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. In the fourth quarter of 2016, Knife River and the plan entered into a settlement agreement whereby the plan administrator assessed Knife River's final withdrawal liability with quarterly payments of approximately \$42,000 until all benefits are satisfied. Knife River discounted the expected future payments. Based on this calculation, Knife River adjusted its liability accrual from \$16.4 million to \$5.2 million in the fourth quarter of 2016.

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

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multiemployer health and welfare plans, were \$51.7€million, \$36.1€million and \$31.4€million for the years ended December€31, 2017, 2016 and 2015, respectively.

Amounts contributed in 2017, 2016 and 2015 to defined contribution multiemployer plans were \$32.2€million, \$23.8€million and \$19.5€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:

	2017		2016	
	(In thousands)			
Big Stone Station:				
Utility plant in service	\$	158,084	\$	157,144
Less accumulated depreciation		51,740		49,568
	\$	106,344	\$	107,576
Coyote Station:				
Utility plant in service	\$	155,287	\$	156,334
Less accumulated depreciation		103,897		105,928
	\$	51,390	\$	50,406
Wygen III:				
Utility plant in service	\$	65,065	\$	66,251
Less accumulated depreciation		7,652		7,550
	\$	57,413	\$	58,701

Note€16 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The jurisdictions in which the Company provides service have requested the Company furnish plans for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details on each jurisdiction's request.

IPUC

On August€12, 2016, Intermountain filed an application with the IPUC for a natural gas rate increase of approximately \$10.2€million annually or approximately 4.1€percent above current rates. The request includes rate recovery associated with increased investment in facilities and increased operating expenses. On January€17, 2017, Intermountain provided the IPUC with an updated revenue request of approximately \$9.4 million. On April€28, 2017, the IPUC issued an order approving an increase of approximately \$4.1€million or approximately 1.6€percent above current rates based on a 9.5€percent return on equity effective with service rendered on and after May€1, 2017. On May€18, 2017, Intermountain filed a petition for reconsideration with the IPUC requesting the reconsideration of certain items denied in the order dated April€28, 2017. On June€15, 2017, the IPUC granted the request for reconsideration. On August€17, 2017, Intermountain, the IPUC staff and the interveners of the case filed a stipulation and settlement resolving all issues. The stipulation and settlement reflected an increase of approximately \$1.2€million or 1.36€percent more in annual revenue than the amounts approved on April€28, 2017, as well as changes in billing determinants. The total annual increase in revenue of approximately \$6.7€million was approved by the IPUC on September€14, 2017, with rates effective October€1, 2017.

On January€17, 2018, the IPUC issued a general order initiating the investigation of the impacts of the TCJA. The order required the tax rate reduction to be deferred as a regulatory liability and for companies to report on the expected impacts of the TCJA by March€30, 2018.

MNPUC

On December 21, 2016, Great Plains filed an application with the MNPUC requesting authority to implement a gas utility infrastructure cost tariff of approximately \$456,000 annually. The tariff will allow Great Plains to recover infrastructure investments, not previously included in rates, mandated by federal or state agencies associated with Great Plains' pipeline integrity programs. On October 6, 2017, the MNPUC approved the implementation of the natural gas utility infrastructure cost tariff to collect an annual increase of approximately \$456,000. Great Plains submitted a compliance filing on October 10, 2017, and the rates were implemented for service rendered on and after November 1, 2017.

On December 29, 2017, the MNPUC issued a notice of investigation related to tax changes with the enactment of the TCJA. On January 19, 2018, the MNPUC issued a notice of request for information, commission planning meeting and subsequent comment period. Great Plains was to provide preliminary impacts of the TCJA by January 30, 2018. A commission planning meeting was held on February 6, 2018, to discuss the impacts of the TCJA. Initial filings addressing the impacts of the TCJA are to be submitted by March 2, 2018.

MTPSC

On September 25, 2017, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase of approximately \$2.8 million annually or approximately 4.1 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota is also introducing an SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately \$1.6 million or approximately 2.3 percent, subject to refund. On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA for the natural gas segment within the natural gas rate case. On January 12, 2018, Montana-Dakota filed a revised interim increase of approximately \$764,000, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. A hearing is scheduled for April 26, 2018. This matter is pending before the MTPSC.

On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA and to file a proposal for the impacts on the electric segment by March 31, 2018.

NDPSC

On June 30, 2017, Montana-Dakota filed an application for advance determination of prudence and a certificate of public convenience and necessity with the NDPSC to purchase an expansion of the Thunder Spirit Wind farm. The advance determination of prudence would provide Montana-Dakota with assurance that the project is prudent and in the best interest of the public and assists in the recovery of Montana-Dakota's investment upon completion of the project. The expansion is expected to serve customers by the end of 2018 and is estimated to cost approximately \$85 million. On November 16, 2017, the NDPSC granted Montana-Dakota's request for an advance determination of prudence and certificate of public convenience and necessity to acquire and operate the Thunder Spirit Wind farm expansion.

On July 21, 2017, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase of approximately \$5.9 million annually or approximately 5.4 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota is also introducing an SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately \$4.6 million or approximately 4.2 percent, subject to refund. On September 6, 2017, the NDPSC approved the request for interim rates effective with service rendered on or after September 19, 2017. On January 12, 2018, Montana-Dakota requested a delay of the rate case as a result of the enactment of the TCJA to allow the Company time to investigate the implications of the TCJA on the rate case. On February 14, 2018, the NDPSC approved the delay of hearing and scheduled it to begin on May 30, 2018. Also on February 14, 2018, Montana-Dakota filed a revised interim increase request of approximately \$2.7 million, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. This matter is pending before the NDPSC.

On January 10, 2018, the NDPSC issued a general order initiating the investigation into the effects of the TCJA. The order required regulatory deferral accounting on the impacts of the TCJA and for companies to file comments and the expected impacts. On February 15, 2018, Montana-Dakota filed a summary of the primary impacts of the TCJA on the electric and natural gas utilities.

OPUC

On September 29, 2017, Cascade filed an application with the OPUC for an annual pipeline replacement safety cost recovery mechanism of approximately \$784,000 or approximately 1.2 percent of additional revenue. The requested increase includes incremental pipeline replacement investments associated with qualifying pipeline integrity projects. This matter is pending before the OPUC.

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On December 29, 2017, Cascade filed a request with the OPUC to use deferral accounting for the 2018 net benefits associated with the implementation of the TCJA.

SDPUC

On December 29, 2017, the SDPUC issued an order initiating the investigation into the effects of the TCJA. The order required Montana-Dakota to provide comments by February 1, 2018, regarding the general effects of the TCJA on the cost of service in South Dakota and possible mechanisms for adjusting rates. The order also stated that all rates impacted by the federal income tax shall be adjusted effective January 1, 2018, subject to refund.

WUTC

On May 31, 2017, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of approximately \$1.6 million or approximately .75 percent of additional revenue. The requested increase includes incremental pipeline replacement investments associated with qualifying pipeline integrity projects. On October 12, 2017, Cascade filed a required update revising the request to approximately \$1.3 million or approximately .61 percent of additional revenue and on October 26, 2017, the WUTC approved the order with rates effective November 1, 2017.

On August 31, 2017, Cascade filed an application with the WUTC for a natural gas rate increase of approximately \$5.9 million annually or approximately 2.7 percent above current rates. The requested increase includes costs associated with increased infrastructure investment and the associated operating expenses. Also included in the request is recovery of operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On January 3, 2018, the WUTC filed a bench request requiring Cascade to provide information related to the impacts of the TCJA on Cascade's revenue requirement and a proposed ratemaking treatment of those impacts. On January 12, 2018, Cascade filed a response to the bench request reducing the revenue requirement to approximately \$1.7 million annually, which includes the estimated impacts of the TCJA. This matter is pending before the WUTC.

WYPSC

On December 29, 2017, the WYPSC issued a general order requiring regulatory deferral accounting on the impacts of the TCJA. A technical conference was held on February 6, 2018, to discuss the implications of the TCJA.

FERC

On September 1, 2017, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff, which reflects an incremental increase of approximately \$2.5 million to include a revenue requirement for the Company's multivalue project, for a total of \$13.6 million, which was effective January 1, 2018.

Montana-Dakota and certain MISO Transmission Owners with projected rates submitted a filing to the FERC on February 1, 2018, requesting the FERC to waive certain provisions of the MISO tariff in order for Montana-Dakota and certain MISO Transmission Owners with projected rates to revise their rates to reflect the reduction in the corporate tax rate. Under the MISO tariff, rates are to be changed only on an annual basis with any changes reflected in subsequent true-ups. If the waiver is granted, MISO expects to implement new rates reflecting the reduction in the tax rate beginning with services rendered on March 1, 2018, and will re-bill January and February 2018 services to reflect the new rates.

On February 7, 2018, WBI Energy Transmission announced it will hold an initial rate change pre-filing settlement meeting with customers on April 10, 2018. In accordance with WBI Energy Transmission's offer of settlement and stipulation and agreement with the FERC dated June 4, 2014, the Company is to make a filing with new proposed rates to be effective no later than May 1, 2019. Assuming a five-month suspension period, WBI Energy Transmission would expect to file by October 31, 2018.

Note 17 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. 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. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4)

the matter involves novel or unsettled legal theories. The Company accrued liabilities of \$35.4€million and \$31.8€million, which have not been discounted, including liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at December€31, 2017 and 2016, respectively. This includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

Litigation

Construction Services€Capital Electric provided employees in 2012 to perform work for a contractor on a project in Kansas. One of the Capital Electric employees was injured while working on the project and brought a lawsuit against the contractor. Judgment was entered in favor of the employee and his spouse on November€3, 2016, in the amount of \$44.8€million following a court determination that the employee's injuries were caused by the contractor's negligence. The contractor claims that Capital Electric was contractually required, but failed, to name the contractor as an additional insured under any liability policy in effect at the time of the project and that such failure resulted in the entry of judgment against the contractor. In March 2017, Capital Electric filed a petition for declaratory judgment in the District Court of Wyandotte County, Kansas for a judicial determination that any agreement between Capital Electric and the contractor for the project did not require Capital Electric to include the contractor as an additional insured under any liability policy issued to Capital Electric and that if such an agreement was found to exist, it would be void and unenforceable under Kansas law. Subsequent to December€31, 2017, the matter has been settled with Capital Electric being released from all claims of liability and the declaratory judgment action being dismissed.

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 \$100€million. On January€6, 2017, Region€10 of the EPA issued an ROD with its selected remedy for cleanup of the in-river portion of the site. Implementation of the remedy is expected to take up to 13€years with a present value cost estimate of approximately \$1€billion. Corrective action will not be taken until remedial design/remedial action plans are approved by the EPA. 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 matter.

Manufactured Gas Plant Site€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. The Oregon DEQ released an ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. The total estimated cost for the selected remediation, including long-term maintenance, is approximately \$3.5€million of which \$400,000 has been incurred. It is not known at this time what share of the cleanup costs will

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. The commitment terms vary in length, up to 43 years. The commitments under these contracts as of December 31, 2017, were:

	2018	2019	2020	2021	2022	Thereafter
	(In thousands)					
Purchase commitments	\$ 360,751	\$ 215,005	\$ 162,424	\$ 135,334	\$ 99,068	\$ 773,820

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2017, 2016 and 2015, were \$516.1 million, \$539.3 million and \$842.1 million, respectively.

Guarantees

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which totaled \$56.3 million at December 31, 2017, and are expected to mature in 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. The estimated fair values of the indemnity asset and guarantee liability are reflected in deferred charges and other assets - other and deferred credits and other liabilities - other, respectively, on the Consolidated Balance Sheets. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox Basin assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

In 2009, multiple sale 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, 2017, the fixed maximum amounts guaranteed under these agreements aggregated \$108.0 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$6.4 million in 2018; \$25.9 million in 2019; \$68.7 million in 2020; \$500,000 in 2021; \$500,000 in 2022; \$2.0 million thereafter; and \$4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2017. 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, 2017, the fixed maximum amounts guaranteed under these letters of credit aggregated \$34.0 million, all of which expire in 2018. There were no amounts outstanding under the above letters of credit at December 31, 2017. 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.

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, 2017.

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, 2017, approximately \$616.5 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

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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.

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Company's Consolidated Balance Sheets and is recovered from customers as a component of electric fuel and purchased power.

The 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, 2017, the Company's exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage was \$40.8 million.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2017 and 2016:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
(In thousands, except per share amounts)				
<u>2017</u>				
Operating revenues	\$ 937,925	\$ 1,067,639	\$ 1,272,548	\$ 1,165,239
Operating expenses	870,813	987,960	1,116,171	1,039,695
Operating income	67,112	79,679	156,377	125,544
Income from continuing operations	35,638	44,405	89,549	115,394
Income (loss) from discontinued operations attributable to the Company, net of tax	1,687	(3,190)	(2,198)	(82)
Net income attributable to the Company	37,325	41,215	87,351	115,312
Earnings per common share - basic:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations attributable to the Company, net of tax	.01	(.01)	(.01)	•
Earnings per common share - basic	.19	.21	.45	.59
Earnings per common share - diluted:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations attributable to the Company, net of tax	.01	(.01)	(.01)	•
Earnings per common share - diluted	.19	.21	.45	.59
Weighted average common shares outstanding:				
Basic	195,304	195,304	195,304	195,304
Diluted	196,023	195,973	195,783	195,617
<u>2016</u>				
Operating revenues	\$ 860,214	\$ 1,043,948	\$ 1,208,567	\$ 1,016,099
Operating expenses	798,229	954,983	1,061,883	904,613
Operating income	61,985	88,965	146,684	111,486
Income from continuing operations	31,865	46,298	88,386	66,547
Loss from discontinued operations attributable to the Company, net of tax	(6,996)	(155,451)	(5,400)	(816)
Net income (loss) attributable to the Company	24,869	(109,153)	82,986	65,731
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	.16	.24	.45	.34
Discontinued operations attributable to the Company, net of tax	(.03)	(.80)	(.03)	,
Earnings (loss) per common share - basic	.13	(.56)	.42	.34
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	.16	.24	.45	.33
Discontinued operations attributable to the Company, net of tax	(.03)	(.80)	(.03)	,
Earnings (loss) per common share - diluted	.13	(.56)	.42	.33
Weighted average common shares outstanding:				
Basic	195,284	195,304	195,304	195,304
Diluted	195,284	195,699	195,811	195,889

Notes:

- f* Fourth quarter 2016 reflects a reduction to a previously recorded MEPP withdrawal liability of \$11.1 million (before tax). For more information, see Note 14.
- f* First quarter 2016 has been recast to present the results of operations of Dakota Prairie Refining as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former refining segment and do not meet the criteria for income (loss) from discontinued operations.
- f* Fourth quarter 2017 reflects an income tax benefit of \$39.5 million related to the TCJA. For more information, see Note 11.

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 second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell substantially all of

Part II

Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. Prior to the asset sales, Fidelity was significantly involved in the development and production of oil and natural gas resources. Upon the completion of the asset sales, the Company had no remaining proved oil, NGL or natural gas reserves. 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 were 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. For more information, see Note 2.

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
Andeavor Field Services LLC	Formerly QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7% ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
Calumet	Calumet Specialty Products Partners, L.P.
Capital Electric	Capital Electric Construction Company, Inc., a direct wholly owned subsidiary of MDU Construction Services
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
Centennial Resources Company	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial 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% 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 previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
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
IPUC	Idaho Public Utilities Commission
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
LWG	Lower Willamette Group
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.
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
MTPSC	Montana Public Service Commission
MW	Megawatt

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NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream's 50% ownership interests were sold effective January 1, 2017)
PRP	Potentially Responsible Party
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
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct 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% 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, 2017, 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

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information

The following table includes information as of December 31, 2017, with respect to the Company's 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⁾	692,761 ⁽²⁾	\$, ⁽³⁾	4,662,030 ⁽⁴⁾⁽⁵⁾
Equity compensation plans not approved by stockholders	N/A	N/A	N/A
Total	692,761	\$,	4,662,030

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan and the Long-Term Performance-Based Incentive Plan.

(2) Consists of performance shares.

(3) No weighted average exercise price is shown for the performance shares.

(4) This amount includes 4,307,574 shares 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 includes 354,456 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors, excluding the Chair of the Board, are awarded shares equal in value to \$110,000 annually and the Chair of the Board is awarded shares equal in value to \$145,000 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 remaining information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 15. Exhibits, Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 - Financial Statements and Supplementary Data.

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Consolidated Statements of Comprehensive Income for each of the three years in the period ended December 31, 2017	54
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Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2017	57
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2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report.

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Condensed Statements of Income and Comprehensive Income for each of the three years in the period ended December 31, 2017	108
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MDU RESOURCES GROUP, INC. Schedule I - Condensed Financial Information of Registrant (Unconsolidated) Condensed Statements of Income and Comprehensive Income

Years ended December 31,	2017	2016	2015
	(In thousands)		
Operating revenues	\$ 623,693	\$ 561,266	\$ 556,112
Operating expenses	516,524	469,062	478,198
Operating income	107,169	92,204	77,914
Other income	1,331	1,491	8,318
Interest expense	31,997	31,519	23,562
Income before income taxes	76,503	62,176	62,670
Income taxes	13,800	6,355	15,882
Equity in earnings of subsidiaries from continuing operations	222,283	177,275	129,601
Net income from continuing operations	284,986	233,096	176,389
Equity in loss of subsidiaries from discontinued operations attributable to the Company	(3,783)	(168,663)	(798,824)
Loss on redemption of preferred stocks	600	,	,
Dividends declared on preferred stocks	171	685	685
Earnings (loss) on common stock	\$ 280,432	\$ 63,748	\$ (623,120)
Comprehensive income (loss)	\$ 279,602	\$ 65,848	\$ (617,480)

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,	2017	2016
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	\$ 843	\$ 4,159
Receivables, net	83,453	80,467
Accounts receivable from subsidiaries	34,029	34,424
Inventories	13,864	17,352
Prepayments and other current assets	34,400	24,531
Total current assets	166,589	160,933
Investments	76,779	70,370
Investment in subsidiaries	1,704,908	1,603,874
Property, plant and equipment	2,631,161	2,502,264
Less accumulated depreciation, depletion and amortization	797,130	756,191
Net property, plant and equipment	1,834,031	1,746,073
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	175,599	183,654
Total deferred charges and other assets	180,411	188,466
Total assets	\$ 3,962,718	\$ 3,769,716
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	\$ 100,011	\$ 110
Accounts payable	47,000	37,697
Accounts payable to subsidiaries	7,234	5,592
Taxes payable	13,717	14,992
Dividends payable	38,573	37,767
Accrued compensation	20,017	16,086
Other accrued liabilities	36,881	34,929
Total current liabilities	263,433	147,173
Long-term debt	612,493	679,667
Deferred credits and other liabilities:		
Deferred income taxes	147,847	270,126
Other	509,902	356,506
Total deferred credits and other liabilities	657,749	626,632
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	•	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, \$1.00 par value		
Issued - 195,843,297 shares in 2017 and 2016	195,843	195,843
Other paid-in capital	1,233,412	1,232,478
Retained earnings	1,040,748	912,282
Accumulated other comprehensive loss	(37,334)	(35,733)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,429,043	2,301,244
Total stockholders' equity	2,429,043	2,316,244
Total liabilities and stockholders' equity	\$ 3,962,718	\$ 3,769,716

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

Part IV

MDU RESOURCES GROUP, INC. Schedule I - Condensed Financial Information of Registrant (Unconsolidated) Condensed Statements of Cash Flows

Years ended December 31,	2017		2016		2015	
	(In thousands)					
Net cash provided by operating activities	\$	284,075	\$	238,125	\$	255,273
Investing activities:						
Capital expenditures		(146,370)		(159,570)		(349,985)
Net proceeds from sale or disposition of property and other		(5,665)		3,784		3,268
Investments in and advances to subsidiaries		(40,000)		(5,000)		(7,000)
Advances from subsidiaries		40,000		15,000		100,000
Investments		(468)		(129)		5
Net cash used in investing activities		(152,503)		(145,915)		(253,712)
Financing activities:						
Issuance of long-term debt		70,080		106,420		224,185
Repayment of long-term debt		(37,569)		(50,010)		(108,008)
Proceeds from issuance of common stock		•		,		21,898
Dividends paid		(150,727)		(147,156)		(142,835)
Redemption of preferred stock		(15,600)		,		,
Repurchase of common stock		(564)		,		,
Tax withholding on stock-based compensation		(508)		(226)		,
Net cash used in financing activities		(134,888)		(90,972)		(4,760)
Increase (decrease) in cash and cash equivalents		(3,316)		1,238		(3,199)
Cash and cash equivalents - beginning of year		4,159		2,921		6,120
Cash and cash equivalents - end of year	\$	843	\$	4,159	\$	2,921

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 from subsidiaries is reported as equity in earnings 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 Item 8 - Note 1 for information on the computation of earnings (loss) per common share.

Note 2 - Debt At December 31, 2017, the Company had long-term debt maturities, excluding unamortized debt issuance costs, of \$100.0 million in 2018, \$74.5 million in 2019, \$700,000 in 2020, \$700,000 in 2021, \$700,000 in 2022 and \$538.1 million scheduled to mature in years after 2022.

For more information on debt, see Item 8 - Note 6.

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 \$116.1 million, \$115.8 million and \$110.6 million for the years ended December 31, 2017, 2016 and 2015, respectively.

MDU RESOURCES GROUP, INC.

Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2017, 2016 and 2015

Description	Balance at Beginning of Year	Additions			Deductions **	Balance at End of Year
		Charged to Costs and Expenses	Other *			
(In thousands)						
Allowance for doubtful accounts:						
2017	\$ 10,479	\$ 7,024	\$ 989	\$ 10,423	\$ 8,069	
2016	9,835	8,302	851	8,509	10,479	
2015	9,511	11,343	1,012	12,031	9,835	

* 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.

Item 16. Form 10-K Summary

None.

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference				
			Form	Period Ended	Exhibit	Filing Date	File Number
2(a)	Membership Interest Purchase Agreement, dated as of June 24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC		8-K/A		2.1	7/21/16	1-03480
2(b)	Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P.		8-K/A		2.2	7/21/16	1-03480
2(c)	Amendment No. 1 to Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P.		8-K/A		2.3	7/21/16	1-03480
3(a)	Restated Certificate of Incorporation of MDU Resources Group, Inc., as amended, dated May 13, 2010		10-Q	9/30/10	3(a)	11/3/10	1-03480
3(b)	Bylaws of MDU Resources Group, Inc., as amended and restated on February 16, 2017		8-K		3.1	2/21/17	1-03480
4(a)	Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee		S-8		4(f)	1/21/04	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		10-K	12/31/09	4(c)	2/17/10	1-03480
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		10-Q	6/30/05	4(a)	8/3/05	1-03480
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		10-Q	6/30/06	4(a)	8/4/06	1-03480

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Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference				
			Form	Period Ended	Exhibit	Filing Date	File Number
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		10-K	12/31/15	4(e)	2/19/16	1-03480
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		10-K	12/31/15	4(f)	2/19/16	1-03480
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		10-K	12/31/11	4(e)	2/24/12	1-03480
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		10-Q	9/30/12	4	11/7/12	1-03480
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		10-Q	6/30/14	4(a)	8/8/14	1-03480
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		10-Q	6/30/14	4(b)	8/8/14	1-03480
4(k)	Fourth Amended and Restated Credit Agreement, dated as of September 23, 2016, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto		10-Q	9/30/16	4	11/7/16	1-03480
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		8-K		4	8/16/07	1-03480
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		10-Q	9/30/08	4(b)	11/5/08	1-03480
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		8-K		4	8/12/92	1-07196
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		10-Q	6/30/93	4		1-07196
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		8-K		4.1	1/26/05	1-07196
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		8-K		4.1	3/8/07	1-07196
+10(a)	MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated May 10, 2017		10-Q	6/30/17	10(d)	8/4/17	1-03480
+10(b)	MDU Resource Group, Inc. Director Compensation Policy, as amended May 10, 2017		10-Q	6/30/17	10(a)	8/4/17	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference				
			Form	Period Ended	Exhibit	Filing Date	File Number
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008		10-Q	6/30/08	10(a)	8/7/08	1-03480
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011		10-Q	6/30/11	10(a)	8/5/11	1-03480
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012		10-Q	6/30/12	10(a)	8/7/12	1-03480
+10(f)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016		10-K	12/31/15	10(f)	2/19/16	1-03480
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended May 10, 2017, and Rules and Regulations, as amended May 9, 2017		10-Q	6/30/17	10(b)	8/4/17	1-03480
+10(h)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2015		8-K		10.3	2/18/15	1-03480
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.3	2/18/16	1-03480
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 16, 2017		8-K		10.1	2/21/17	1-03480
+10(k)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.2	2/18/16	1-03480
+10(l)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, dated May 15, 2014		8-K		10.1	5/15/14	1-03480
+10(m)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	1-03480
+10(n)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of October 10, 2017		10-Q	9/30/17	10(b)	11/3/17	1-03480
+10(o)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended May 10, 2017		10-Q	6/30/17	10(c)	8/4/17	1-03480
+10(p)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated January 1, 2017		10-Q	3/31/17	10(a)	5/8/17	1-03480
+10(q)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 31, 2017		10-Q	3/31/17	10(b)	5/8/17	1-03480
+10(r)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated April 10, 2017		10-Q	6/30/17	10(e)	8/4/17	1-03480
+10(s)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 30, 2017		10-Q	9/30/17	10(a)	11/3/17	1-03480
+10(t)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(u)	Martin A. Fritz Offer Letter, dated July 1, 2015		8-K		10.2	7/2/15	1-03480
+10(v)	Jason L. Vollmer Offer Letter, dated March 7, 2016		8-K		10.2	3/8/16	1-03480
+10(w)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends	X					
21	Subsidiaries of MDU Resources Group, Inc.	X					
23	Consent of Independent Registered Public Accounting Firm	X					
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					

Part IV

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference				
			Form	Period Ended	Exhibit	Filing Date	File Number
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
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	X					
95	Mine Safety Disclosures	X					
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document						
101.SCH	XBRL Taxonomy Extension Schema Document						
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document						
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document						
101.LAB	XBRL Taxonomy Extension Label Linkbase Document						
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document						

+€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 23, 2018 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
<u>/s/ David L. Goodin</u> David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 23, 2018
<u>/s/ Jason L. Vollmer</u> Jason L. Vollmer (Vice President, Chief Financial Officer and Treasurer)	Chief Financial Officer	February 23, 2018
<u>/s/ Stephanie A. Barth</u> Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 23, 2018
<u>/s/ Harry J. Pearce</u> Harry J. Pearce (Chairman of the Board)	Director	February 23, 2018
<u>/s/ Thomas Everist</u> Thomas Everist	Director	February 23, 2018
<u>/s/ Karen B. Fagg</u> Karen B. Fagg	Director	February 23, 2018
<u>/s/ Mark A. Hellerstein</u> Mark A. Hellerstein	Director	February 23, 2018
<u>/s/ A. Bart Holaday</u> A. Bart Holaday	Director	February 23, 2018
<u>/s/ Dennis W. Johnson</u> Dennis W. Johnson	Director	February 23, 2018
<u>/s/ William E. McCracken</u> William E. McCracken	Director	February 23, 2018
<u>/s/ Patricia L. Moss</u> Patricia L. Moss	Director	February 23, 2018
<u>/s/ John K. Wilson</u> John K. Wilson	Director	February 23, 2018



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 23, 2018

Fellow Stockholders:

I invite you to join me, our Board of Directors and members of our senior management team at our annual stockholder meeting at 11 a.m., Central Daylight Saving Time, on May 8, 2018, at 909 Airport Road in Bismarck, North Dakota.

In addition to the business we will conduct at the meeting, I will describe the significant drivers of our strong 2017 financial results as well as the growth projects we have underway or soon to be started this year. Absent the benefit we recorded in 2017 from implementing the Tax Cuts and Jobs Act, which was signed into law December 22, our earnings were up about 5 percent over 2016. This shows the strength of our two-pillar approach to our operations, with strong performance from both our regulated energy delivery businesses and our construction materials and services businesses.

We remain committed to returning the value to you that you expect from your investment in MDU Resources. In 2017, we marked our 80th consecutive year of paying dividends to our stockholders and we increased our dividend payment for the 27th consecutive year, a feat achieved by fewer than 100 other U.S.-listed companies.

As we celebrate our 70th year of being listed on the New York Stock Exchange, we remain committed to Building a Strong America. We hope you share in our excitement about the momentum we have going into 2018 and the substantial opportunities for growth at all of our businesses.

In our Proxy Statement this year, we have included additional summarized information about our environmental and social practices. If you would like greater detail about our sustainability efforts, please refer to our Sustainability Report on our website at www.mdu.com.

I look forward to seeing you May 8. Details on how to receive a ticket to attend our annual meeting are included on the [Notice of Annual Meeting](#) and [page 61](#) of this Proxy Statement.

If you are not able to attend the annual stockholder meeting, your vote is still important to us. Please promptly follow the instructions on your notice or proxy card to vote and make sure your shares are represented.

We appreciate your continued investment in MDU Resources.

Sincerely yours,

David L. Goodin
President and Chief Executive Officer



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 MAY 8, 2018**

March 23, 2018

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, May 8, 2018, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

Items of Business	<ol style="list-style-type: none"> 1. Election of directors; 2. Advisory vote to approve the compensation paid to the company's named executive officers; 3. Ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2018; and 4. Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.
Record Date	The board of directors has set the close of business on March 9, 2018, 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.
Meeting Attendance	<p>All stockholders as of the record date of March 9, 2018, are cordially invited and urged to attend the annual meeting. You must request an admission ticket in order to attend. If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources Group, Inc. by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.</p> <p>If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or by email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 9, 2018, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.</p> <p>Requests for admission tickets must be received no later than May 1, 2018. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.</p>
Proxy Materials	Notice of Availability of Proxy Materials will be sent on or about March 23, 2018. The Notice contains basic information about the annual meeting and instructions on how to view our proxy materials and vote electronically on the Internet. Stockholders who do not receive the Notice will receive a paper copy of our proxy materials, which will be sent on or about March 29, 2018.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to be Held on May 8, 2018.
The 2018 Notice of Annual Meeting and Proxy Statement and 2017 Annual Report to Stockholders
are available at www.mdu.com/proxymaterials.

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PROXY STATEMENT SUMMARY

To assist you in reviewing the company's 2017 performance and voting your shares, we call your attention to key elements of our 2018 Proxy Statement. The following is only a summary and does not contain all of the information you should consider. You should read the entire Proxy Statement carefully before voting. For more complete information about these topics, please review the complete Proxy Statement and our 2017 Annual Report to Stockholders.

Meeting Information

Time and Date:
11:00 a.m. Central Daylight Saving Time Tuesday, May 8, 2018
Place:
MDU Service Center 909 Airport Road Bismarck, ND

Summary of Stockholder Voting Matters

Voting Matters	Board Vote Recommendation	See Page
Item 1 - Election of Directors	FOR each nominee	8
Item 2 - Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	FOR	26
Item 3 - Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2018	FOR	56

Corporate Governance Highlights

MDU Resources Group, Inc. is committed to strong corporate governance practices. The following highlights our corporate governance practices and policies. See the sections entitled , [Corporate Governance](#) and , [Executive Compensation](#) for more information on the following:

€ Annual Election of All Directors
€ Majority Voting for Directors
€ Succession Planning and Implementation Process
€ Separate Chair and CEO
€ Executive Sessions of Independent Directors at Every Regularly Scheduled Board Meeting
€ Annual Board and Committee Self-Evaluations
€ Risk Oversight by Full Board and Committees
€ All Directors are Independent Other Than Our CEO
€ Mandatory Retirement for Directors at Age 76

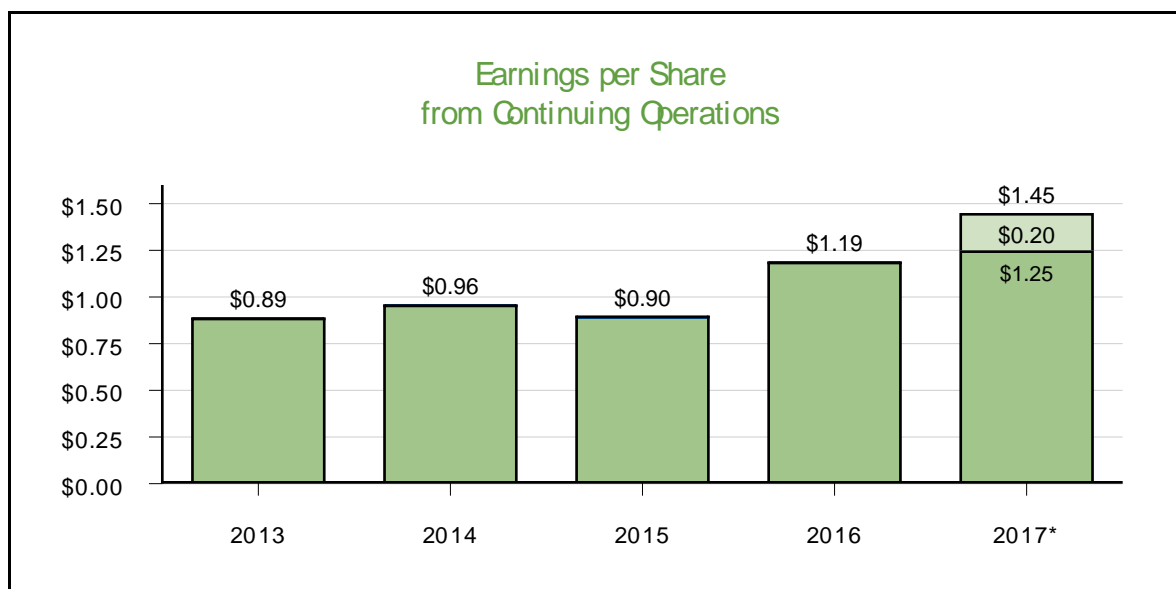
€ All Three Standing Committees Consist Entirely of Independent Directors
€ Active Investor Outreach Program
€ Stock Ownership Requirements for Directors and Executives
€ Anti-Hedging and Anti-Pledging Policies
€ No Related Party Transactions by Our Directors or Executive Officers
€ Compensation Recovery/Clawback Policy
€ Code of Business Conduct and Ethics for Directors, Officers, and Employees
€ Annual Advisory Approval on Executive Compensation
€ Directors May Not Serve on More Than Three Public Boards Including the Company's Board

Business Performance Highlights

Our overall performance in 2017 was consistent with our long-term strategy as we focused on our regulated energy delivery and construction materials and services business segments. In addition to our 2017 financial performance highlighted on the next page, we accomplished:

- The sale of our interest in the Pronghorn natural gas processing plant in January 2017 which reduced the company’s risk by decreasing its exposure to commodity price fluctuations.
- Our construction services segment had record revenues of \$1.37 billion and its backlog at December 31, 2017 was \$708 million, 49% higher than 2016.
- Our construction materials and contracting segment had higher aggregate sales volumes on strong commercial and residential demand in certain regions. Its backlog at year-end of \$486 million, while lower than 2016, is the third largest year-end level for this segment. The segment continues to strategically manage its nearly 1.0 billion tons of aggregate reserves.
- We received advance determination of prudence from the North Dakota Public Service Commission to purchase an expansion of the Thunder Spirit wind farm.
- The pipeline and midstream segment had record transportation volumes in 2017.
- Our pipeline and midstream segment secured sufficient capacity commitments to expand its Line Section 27 natural gas transportation system in the Bakken producing area of northwestern North Dakota. The project will involve the construction of approximately 13 miles of pipeline and associated facilities. The expansion will provide WBI Energy, Inc.’s Line Section 27 pipeline with capacity for over 600,000 dekatherms per day. The targeted in-service date for the project is fall 2018.
- Our pipeline and midstream segment continued permitting, surveying, and acquisition activity for a 38-mile natural gas transmission pipeline to deliver natural gas to eastern North Dakota and far western Minnesota. Following receipt of necessary regulatory approvals and easement acquisition, construction is expected to start and be completed in 2018.
- The board of directors authorized management to evaluate and pursue a holding company reorganization which is intended to provide further separation between the company’s regulated and unregulated businesses and additional financing flexibility as all of the company’s utility operations will be conducted through wholly-owned subsidiaries. The reorganization, which is expected to be effective January 1, 2019, is subject to approval by the Federal Energy Regulatory Commission and various state regulatory commissions.

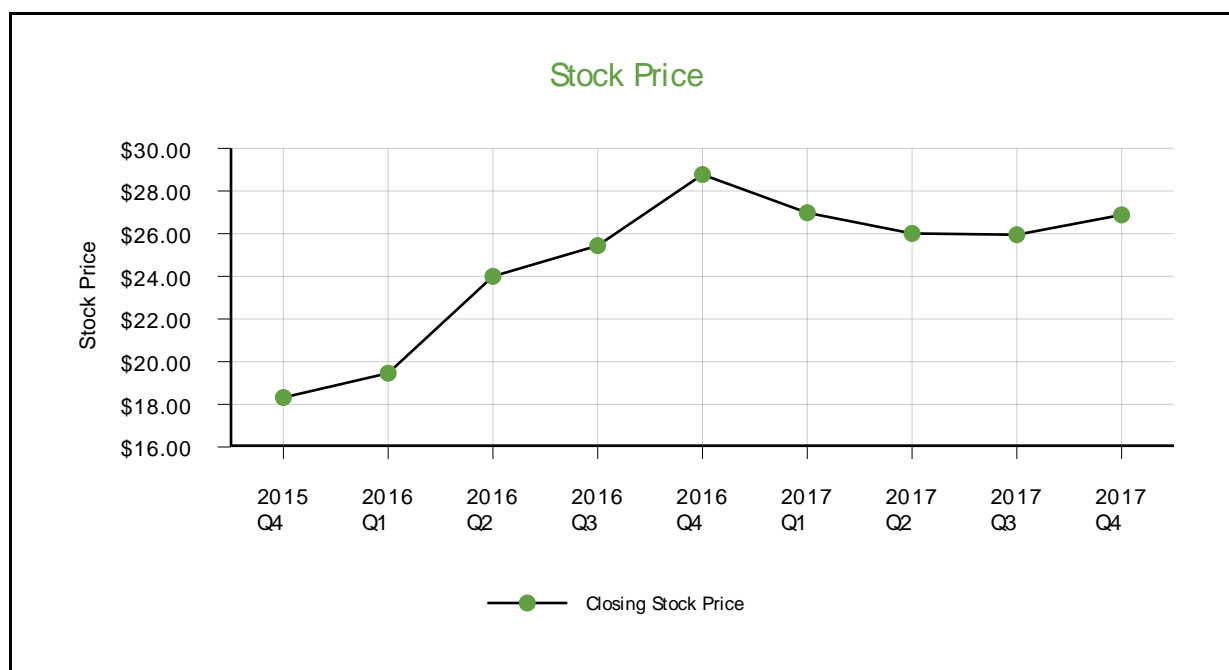
With our accomplishments in 2017, we are optimistic about the company’s future financial performance. The chart below shows our progress over the last five years.



* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of \$1.45 per share which included a benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act, which was signed into law December 22, 2017. The earnings per share absent the federal Tax Cuts and Jobs Act benefit is \$1.25.

2017 Financial Performance Highlights

- Strong year-over-year performance from continuing operations, as well as benefits from the federal Tax Cuts and Jobs Act, resulted in an increase in earnings per share from continuing operations to \$1.45 per share compared to \$1.19 per share in 2016. Excluding the effect of the federal Tax Cuts and Jobs Act, earnings from continuing operations were \$1.25 per share. Including discontinued operations, 2017 earnings were \$280.4 million, or \$1.43 per share, compared to \$63.7 million, or 33 cents per share, in 2016.
 - Electric and natural gas distribution segments earned \$81.6 million, an increase of 17.8%.
 - Pipeline and midstream segment earned \$20.5 million, a decrease of \$2.9 million reflecting the sale of the Pronghorn natural gas processing plant in January 2017.
 - Construction materials and contracting segment earned \$123.4 million, including adjustments of \$41.9 million as a result of the federal Tax Cuts and Jobs Act, compared to 2016 earnings of \$102.7 million.
 - Construction services segment earned \$53.3 million, including adjustments of \$4.3 million as a result of the federal Tax Cuts and Jobs Act, an increase of 44.3% over 2016 earnings of \$33.9 million.
- Return of stockholder value through the dividend
 - Increased dividend for 27th straight year
 - Paid uninterrupted dividend for 80th straight year
- Maintained BBB+ stable credit rating from Standard & Poor's and Fitch Ratings agencies.



27 Years
of Consecutive
Dividend Increases

Dividends Paid
\$716 Million
Over the Last 5 Years

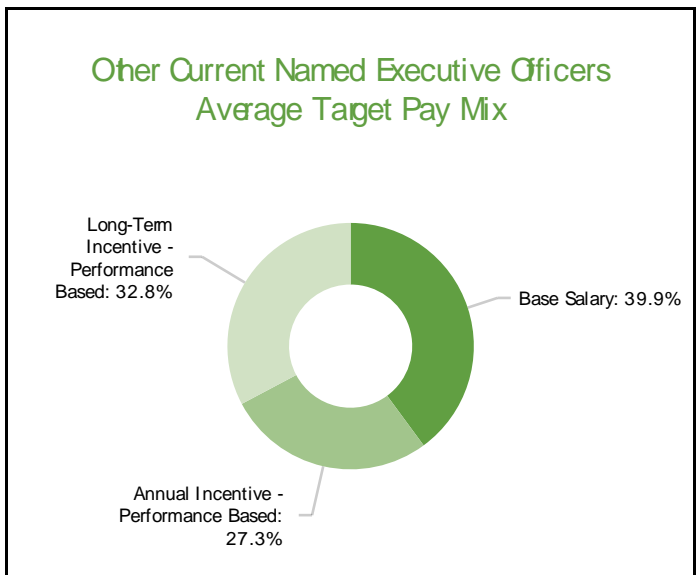
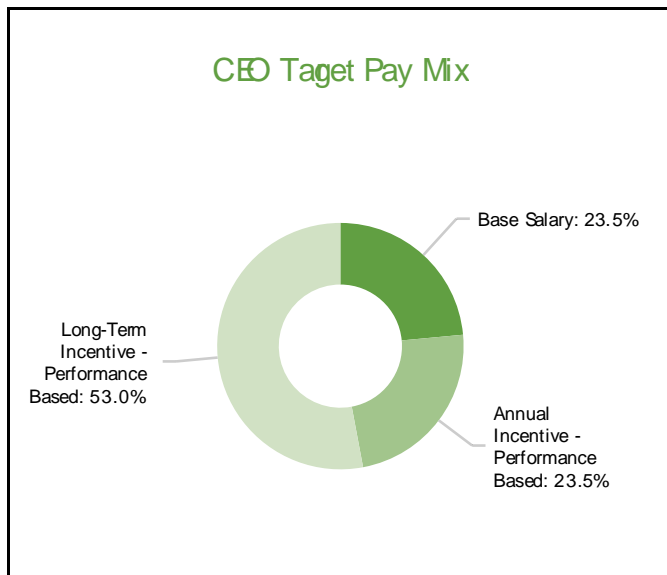
80 Years
of Uninterrupted
Dividend Payments

Compensation Highlights

Executive compensation at the company is focused on performance. Our compensation program is structured to strongly align compensation with the company's performance with a substantial portion of our executive compensation based upon performance incentive awards.

- Over 75% of our chief executive officer's target compensation and over 60% of our other current named executive officers' target compensation is performance based.
- 100% of our chief executive officer's annual and long-term incentive compensation is tied to performance against pre-established, specific, measurable financial goals.
- We require all executive officers to own a significant amount of company stock based upon a multiple of their base salary.

2017 Named Executive Officer Target Pay Mix



- Base salary increase for our chief executive officer was 5% for 2017, and base salary increases for all of our other named executive officers averaged 7.8% in 2017 following base salary freezes for most executive officers in 2016.
- Annual incentive award payout to our chief executive officer for 2017, which was based upon the strong performance at all four of our business units, was 173.7% of his annual incentive target.
- Long-term incentive award payout for the 2015-2017 performance cycle was 144% of target based on a combined 61st percentile ranking of total stockholder return among our peer groups.

Key Features of our Executive Compensation Program

What We Do

Pay for Performance Annual and long-term award incentives tied to performance measures set by the compensation committee comprise the largest portion of executive compensation.

Independent Compensation Committee - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.

Independent Compensation Consultant The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.

Competitive Compensation Executive compensation reflects the executive's performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, the business segment's economic environment, and the actual performance of the overall company or the executive's business segment.

Annual Cash Incentive Payment of annual cash incentive awards are based on business segment and overall company achievement against pre-established financial measures.

Long-Term Equity Incentive - The long-term equity incentive represents 53% of our CEO's and approximately 33% of our other current named executive officer's target compensation in the form of performance shares which may be earned based on relative total stockholder return measured over a three-year period.

Annual Compensation Risk Analysis - We regularly analyze the risks related to our compensation programs and conduct an annual broad risk assessment.

Stock Ownership and Retention Requirements Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. The executive officers must also retain at least 50% of the net after tax shares of stock vested through the long-term incentive plan for the earlier of two years or until termination of employment.

Clawback Policy - If the company's audited financial statements are restated, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

Performance Share Awards Purchased at Market Performance share awards are purchased on the market to avoid shareholder dilution through issuance of authorized but unissued shares.

What We Don't Do

f Stock Options The company does not use stock options as a form of incentive compensation.

f Employment Agreements Current executives do not have employment agreements entitling them to specific payments upon a change of control of the company.

f Perquisites - Executives do not receive perquisites which materially differ from those available to employees in general.

f Tax Gross-Ups - Executive officers do not receive tax gross-ups on any compensation.

f Hedge Stock Executives and directors are not allowed to hedge company securities.

f Pledge Stock Executives and directors are not allowed to pledge company securities in margin accounts or as collateral for loans.

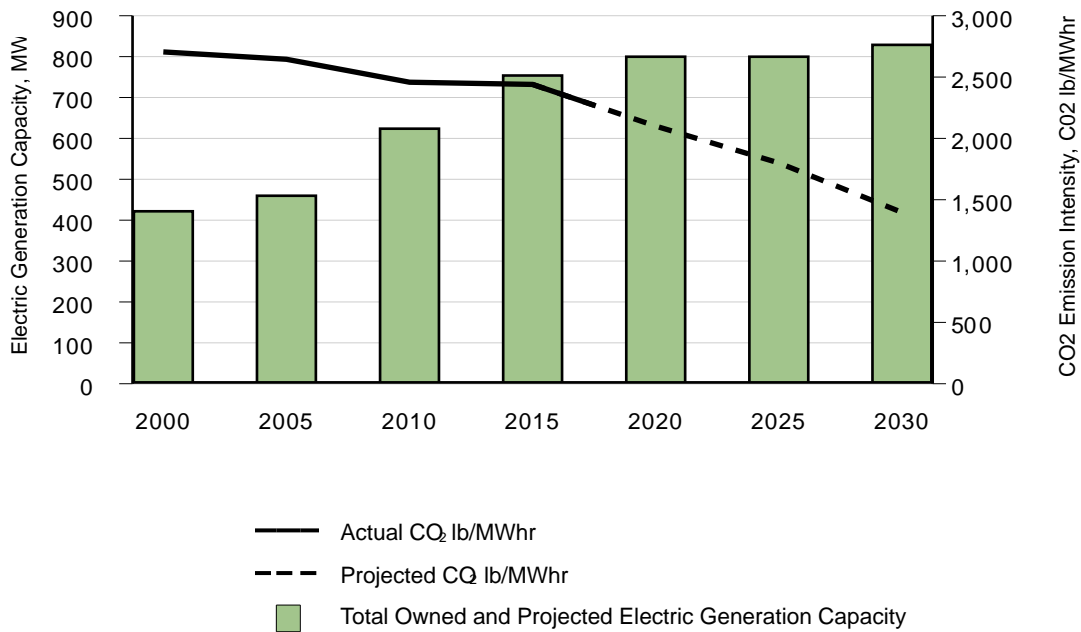
f No Dividends or Dividend Equivalents on Unvested Shares We do not provide for payment of dividends or dividend equivalents on unvested share awards.

Corporate Responsibility, Environmental, and Sustainability

MDU Resources Group, Inc. is Building a Strong America, by providing essential products and services to our customers. To ensure we can continue to provide these products and services in the communities where we do business, we recognize that we must preserve the trust our communities place in us to be a good corporate citizen. We remain committed to pursuing responsible corporate governance and environmental practices, and to maintaining the health and safety of the public and our employees. These are some highlights of our recent efforts regarding sustainability:

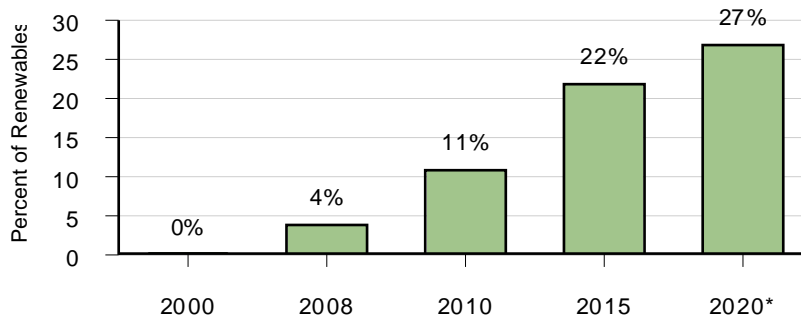
- As our generation resource capacity has increased, the CO₂ emission intensity of our electric generation resource fleet has been reduced by more than 25% since 2003. We expect it to continue to decline.

CO₂ Emission Intensity



- Renewable resources comprised approximately 22% of our electric generation resource nameplate capacity in 2017.
- We received advance determination of prudence for the expansion of the Thunder Spirit wind farm to be completed in 2018. The expansion will bring capacity of the Thunder Spirit wind farm to approximately 155 megawatts which will increase the company's nameplate electric renewable generation capacity to approximately 27%.

Percent of Renewable Generation Resources



* Projected based upon expansion of the Thunder Spirit wind farm.

- Approximately 24% of the electricity delivered to our customers from company-owned generation in 2017 was from renewable resources.
- We invested approximately \$3.7 million in environmental emission control equipment and improvements at our coal-fired electric generation plants bringing the total of such investments to approximately \$125 million since 2013. The investments have resulted in substantial reductions in mercury, SO₂, NOX, and filterable particulate from our coal-fired electric generation resources.
- The company's utility companies received high scores in customer satisfaction. Intermountain Gas Company ranked first, Cascade Natural Gas Corporation second, and Montana-Dakota Utilities Co. fourth, among West Region mid-sized natural gas utilities in the 2017 J.D. Power Gas Utility Residential Customer Satisfaction Survey.
- We were recognized on the Thomson Reuters 2017 Top 25 Global Multiline Utilities list. The list recognizes companies that have demonstrated a commitment to energy leadership in these areas: financial, management and investor confidence, risk and resilience, legal compliance, innovation, people and social sustainability, environmental impact, and reputation.
- We, along with a partner, continued construction of approximately 160 miles of 345-kilowatt electric transmission line which will facilitate delivery of renewable wind energy from North Dakota to eastern markets.
- Montana-Dakota Utilities Co. received approval to expand its Commercial Demand Response Program which will enable further reduction of peak electric demand of approximately 25 megawatts by our commercial and industrial customers.
- Knife River Corporation produces and places warm-mix asphalt in applications where warm-mix asphalt is allowed. Warm-mix asphalt is produced at cooler temperatures than traditional hot-mix asphalt methods, which reduces the amount of fuel needed in the production process and thereby reduces emissions and fumes. Knife River Corporation produced over 653,000 tons in 2014, 640,000 tons in 2015, 831,000 tons in 2016, and 722,000 tons in 2017 of warm-mix asphalt.
- Knife River Corporation continued its practice of recycling and reusing building materials. This conserves natural resources, uses less energy, alleviates waste disposal problems in local landfills, and ultimately costs less for the consumer. Knife River Corporation used over 697,000 tons in 2014, 989,000 tons in 2015, 1,030,000 tons in 2016, and 1,096,000 tons in 2017 of recycled asphalt pavement in asphalt production.
- Our subsidiary, Bombard Renewable Energy, was ranked No. 26 on Solar Power World's 2017 Top 500 Solar Contractors List. The list ranks companies according to their influence in the U.S. solar industry based on how many kilowatts of solar generation they installed in 2016.
- The MDU Resources Foundation awarded grants of \$1.84 million to educational and nonprofit institutions in 2017. Since its incorporation in 1983, the Foundation has contributed more than \$32.4 million to worthwhile causes in categories of education, civic and community activities, culture and arts, environmental stewardship, and health and human services.
- We encourage and support community volunteerism by our employees. The MDU Resources Foundation contributes a \$500 grant to an eligible nonprofit organization after an employee volunteers a minimum of 25 hours to the organization during non-company hours during a calendar year. In 2017, the Foundation granted \$47,200 under this program matching over 5,400 employee volunteer hours.
- We were recognized as a 2020 Women on Boards Winning ,Wf Company for being a champion on board diversity by having 20% or more of our board seats held by women.
- We received the Missouri Slope Areawide United Way 2017 Spirit Award for showing outstanding commitment to the Bismarck-Mandan community through volunteerism and creative workplace campaigns.

24%
of Electricity Generated
from Renewable Resources

Grants Awarded
\$1.84 Million
in 2017

25%
Reduction in CO₂
Since 2003

BOARD OF DIRECTORS


ITEM 1. ELECTION OF DIRECTORS

The nominating and governance committee of the board, reflecting the criteria for election to the board, identifies and reviews possible candidates for the board and recommends the nominees for directors to the board for approval. The committee considers and evaluates suggestions from many sources, including stockholders, regarding possible candidates for directors. Additional information on our board composition and director nomination process is further discussed in our Proxy Statement under [Nominating and Governance Committee](#) in the section entitled [Corporate Governance](#).

Each of the current directors has been nominated for election by the board of directors upon recommendation of the nominating and governance committee and has decided to stand for election, with the exception of A. Bart Holaday who will have attained the mandatory retirement age of 76 years at the time of the annual meeting of stockholders and, therefore, will not stand for re-election. Mr. Holaday has served on the board since 2008, and the company expresses its thanks to Mr. Holaday for his service on the board, the audit committee, and nominating and governance committee. All nominees for director are nominated to serve one-year terms until the annual meeting of stockholders in 2019 and 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, including their ages, years of service as directors, business experience, and service on other boards of directors, including any other directorships on boards of public companies. 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

	<p>Thomas Everist Age 68</p>	<p>Independent Director Since 1995 Compensation Committee</p>	<p>Other Current Public Boards: --Raven Industries, Inc.</p>
<p>Mr. Everist has more than 44 years of business experience in the construction materials and aggregate mining industry. He has business leadership and management experience serving as president and chair of his companies for over 30 years. Mr. Everist also has experience serving as a director and chair of another public company, which enhances his contributions to our board.</p>			

Career Highlights

- ... President and chair of The Everist Company, Sioux Falls, South Dakota, an investment and land development company, since April 2002. Prior to January 2017, The Everist Company was engaged in aggregate, concrete, and asphalt production.
- ... Managing member of South Maryland Creek Ranch, LLC, a land development company; president of SMCR, Inc., an investment company, since June 2006; and managing member of MCR Builders, LLC, which provides residential building services to South Maryland Creek Ranch, LLC, since November 2014.
- ... Director and chair of the board of Everist Health, Inc., Ann Arbor, Michigan, which provides solutions for personalized medicines, since 2002, and chief executive officer from August 2012 to December 2012.
- ... President and chair of L.G. Everist, Inc., Sioux Falls, South Dakota, an aggregate production company, from 1987 to April 2002.

Other Leadership Experience

- ... Director of publicly traded Raven Industries, Inc., Sioux Falls, South Dakota, a general manufacturer of electronics, flow controls, and engineered films, since 1996, and chair from April 2009 to May 2017.
- ... Director of Showplace Wood Products, Inc., Sioux Falls, South Dakota, a custom cabinets manufacturer, since January 2000.
- ... Director of Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, since April 2011.
- ... 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.
- ... Member of the South Dakota Investment Council, the state agency responsible for prudently investing state funds, from July 2001 to June 2006.

Education

- ... Bachelor's degree in mechanical engineering and a master's degree in construction management from Stanford University.

	Karen B. Fagg Age 64	Independent Director Since 2005 Compensation Committee Nominating and Governance Committee
	Ms. Fagg brings experience to our board in construction and engineering, energy, and the responsible development of natural resources, which are all important aspects of our business. In addition to her industry experience, Ms. Fagg has over 20 years of business leadership and management experience, including over eight years as president, chief executive officer, and chair of her own company, as well as knowledge and experience acquired through her service on a number of Montana state and community boards.	

Career Highlights

- ... 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.
- ... President of HKM Engineering, Inc., Billings, Montana, an engineering and physical science services firm, from April 1, 1995 to June 2000, and chair, chief executive officer, and majority owner from June 2000 through March 2008. HKM Engineering, Inc. merged with DOWL LLC on April 1, 2008.
- ... Employed with MSE, Inc., Butte, Montana, an energy research and development company, from 1976 through 1988, and vice president of operations and corporate development director from 1993 to April 1995.
- ... 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, for a four-year term from 1989 through 1992.

Other Leadership Experience

- ... Chair of the Billings Catholic Schools Board since September 2017 and member since December 2011; and board member of St. Vincent's Healthcare since January 2016 and previously from October 2003 until October 2009, including a term as chair.
- ... Former member of several state and community boards, including the First Interstate BancSystem Foundation, from June 2013 to 2016; 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; Board of Trustees of Carroll College from 2005 through 2010; Montana Board of Investments, the state agency responsible for prudently investing state funds, from 2002 through 2006; Montana State University's Advanced Technology Park from 2001 to 2005; and Deaconess Billings Clinic Health System from 1994 to 2002.

Education

- ... Bachelor's degree in mathematics from Carroll College in Helena, Montana.

	David L. Goodin Age 56	Director Since 2013 President and Chief Executive Officer
	As chief executive officer of MDU Resources Group, Inc., Mr. Goodin is the only officer of the company that serves on our board. With over 34 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. In addition, Mr. Goodin provides the board with valuable insight into management's views and perspectives, as well as the day-to-day operations of the company.	

Career Highlights

- ... President and chief executive officer and a director of the company since January 4, 2013.
- ... Prior to January 4, 2013, served as chief executive officer and president of Intermountain Gas Company, Cascade Natural Gas Corporation, Montana-Dakota Utilities Co., and Great Plains Natural Gas Co.
- ... Began his career in 1983 at Montana-Dakota Utilities Co. as a division electrical engineer and served in positions of increasing responsibility until 2007 when he was named president of Cascade Natural Gas Corporation; positions included division electric superintendent, electric systems manager, vice president-operations, and executive vice president-operations and acquisitions.

Other Leadership Experience

- ... Member of the U.S. Bancorp Western North Dakota Advisory Board since January 2013.
- ... Director of Sanford Bismarck, an integrated health system dedicated to the work of health and healing, and Sanford Living Centers since January 2011.
- ... Former 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 Energy Council.

Education

- ... Bachelor of science degree in electrical and electronics engineering from North Dakota State University.
- ... Masters in business administration from the University of North Dakota.
- ... The Advanced Management Program at Harvard School of Business.
- ... Registered professional engineer in North Dakota.

Proxy Statement



Mark A. Hellerstein Independent Director Since 2013
Age 65 Audit Committee

Mr. Hellerstein has extensive business experience in the energy industry as a result of his 17 years of senior management experience and service as board chair of St. Mary Land & Exploration Company (now SM Energy Company). 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.

Career Highlights

- ... 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; 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 chair from 2002 until May 2009.
- ... Several positions prior to joining St. Mary in 1991, including 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.

Other Leadership Experience

- ... Director of Transocean Inc., a leading provider of offshore drilling services for oil and gas wells, from December 2006 to November 2007.
- ... Director of the Denver Children's Advocacy Center, whose mission is to provide a continuum of care for traumatized children and their families, from August 2006 until December 2011, including chair for the last three years.

Education and Professional

- ... Bachelor's degree in accounting from the University of Colorado.
- ... Certified public accountant, on inactive status.



Dennis W. Johnson Independent Director Since 2001
Age 68 Vice Chair of the Board
Audit Committee

Mr. Johnson brings to our board over 43 years of experience in business management, manufacturing, and finance, holding positions as chair, president, and chief executive officer of TMI Corporation for 36 years, as well as through his prior service as a director of the Federal Reserve Bank of Minneapolis. 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.

Career Highlights

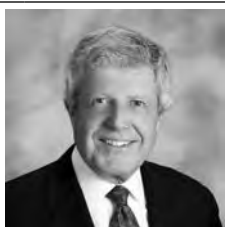
- ... Vice chair of the board of the company effective February 15, 2018.
- ... Chair, president, and chief executive officer of TMI Corporation, and chair and chief executive officer of TMI Transport Corporation, manufacturers of casework and architectural woodwork in Dickinson, North Dakota; employed since 1974 and serving as president or chief executive officer since 1982.

Other Leadership Experience

- ... Member of the Bank of North Dakota Advisory Board of Directors since August 2017.
- ... President of the Dickinson City Commission from July 2000 through October 2015.
- ... Director of the Federal Reserve Bank of Minneapolis from 1993 through 1998.
- ... Served on numerous industry, state, and community boards, including the North Dakota Workforce Development Council (chair); the Decorative Laminate Products Association; the North Dakota Technology Corporation; and the business advisory council of the Steffes Corporation, a metal manufacturing and engineering firm.
- ... 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.

Education

- ... Bachelor of science in electrical and electronics engineering and master of science in industrial engineering from North Dakota State University.

	<p>William E. McCracken Independent Director Since 2013 Age 75 Compensation Committee Nominating and Governance Committee</p>
<p>Mr. McCracken is experienced in information technology and cybersecurity through his tenure at CA, Inc. and International Business Machines Corporation (IBM). This experience coupled with his service as the chair or a member of the board of other public companies and the National Association of Corporate Directors (NACD) enables 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.</p>	

Career Highlights

- ... President of Executive Consulting Group, LLC, a general business consulting firm, from 2002 to present.
- ... 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 as a consultant to the company until December 31, 2013; also as director of CA, Inc. from May 2005 until January 7, 2013, serving as non-executive chair of the board from June 2007 to September 2009, interim executive chair from September 2009 to January 2010, and executive chair from January 2010 to May 2010.
- ... Several executive positions during his 36-year career with IBM, including serving on its Chairman's Worldwide Management Council, a group of the top 30 executives at IBM, from 1995 to 2001.

Other Leadership Experience

- ... Director of the NACD, a nonprofit membership organization for corporate board members, since 2010, and named by the NACD as one of the top 100 most influential people in the boardroom in 2009; served on that organization's 2009 Blue Ribbon Commission (BRC) on risk governance, co-chaired its 2012 BRC on board diversity, and co-chaired its 2015 BRC on board and long-term value creation.
- ... 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.
- ... Chair of the advisory board of the Millstein Center for Global Markets and Corporate Ownership at Columbia University from 2014 to 2018 and member since 2013, and the New York chairman of the Chairman's Forum since 2011.

Education

- ... Bachelor of science in physics and mathematics from Shippensburg University.

	<p>Patricia L. Moss Independent Director Since 2003 Age 64 Compensation Committee Nominating and Governance Committee</p> <p>Other Current Public Boards: --First Interstate BancSystem, Inc. --Aquila Tax Free Trust of Oregon</p>
<p>Ms. Moss has business experience and knowledge of the Pacific Northwest economy and state, local, and regional issues where a significant portion of our operations are located. Ms. Moss provides our board with experience in finance and banking, as well as experience in business development through her work at Cascade Bancorp and Bank of the Cascades, and on the Oregon Investment Fund Advisory Council, the Oregon Business Council, and the Oregon Growth Board. Ms. Moss also has experience as a certified senior professional in human resources.</p>	

Career Highlights

- ... President and chief executive officer of Cascade Bancorp, a financial holding company, Bend, Oregon, from 1998 to January 3, 2012; 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; and chief operating officer, chief financial officer and secretary of Cascade Bancorp from 1987 to 1998.

Other Leadership Experience

- ... Director of First Interstate BancSystem, Inc., since May 30, 2017.
- ... Director of Cascade Bancorp and Bank of the Cascades from 1993, and vice chair from January 3, 2012 until May 30, 2017 when Cascade Bancorp merged into First Interstate BancSystem, Inc., and became First Interstate Bank.
- ... Chair of the Bank of the Cascades Foundation Inc. since 2014; co-chair of the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, since May 2012; and member of the Board of Trustees for the Aquila Tax Free Trust of Oregon, a mutual fund created especially for the benefit of Oregon residents, since June 2015 and January 2002 to May 2005.
- ... Former director of the Oregon Investment Fund Advisory Council, a state-sponsored program to encourage the growth of small businesses in Oregon; the Oregon Business Council, with a mission to mobilize business leaders to contribute to Oregon's quality of life and economic prosperity; the North Pacific Group, Inc., a wholesale distributor of building materials, industrial, and hardwood products; Clear Choice Health Plans Inc., a multi-state insurance company; and City of Bend's Juniper Ridge management advisory board.

Education

- ... Bachelor of science in business administration from Linfield College in Oregon and master's studies at Portland State University.
- ... Commercial banking school certification at the ABA Commercial Banking School at the University of Oklahoma.

Proxy Statement

	<p>Harry J. Pearce Age 75</p>	<p>Independent Director Since 1997 Chair of the Board</p>
<p>Mr. Pearce provides our board with public company leadership with his multinational business management experience and proven leadership skills through his position as vice chair 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 chair, and Nortel Networks Corporation, where he also was chair. 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.</p>		

Career Highlights

... Chair of the board of the company effective August 17, 2006; lead director from February 15, 2001 until August 17, 2006; and vice chair of the board from November 16, 2000 until February 15, 2001.

... Vice chair and director of General Motors Corporation from January 1, 1996 to May 2001; general counsel from 1987 to 1994.

... Senior partner in the Pearce & Durick law firm in Bismarck, North Dakota, prior to joining General Motors in 1987.

Other Leadership Experience

... Director of Hughes Electronics Corporation, a General Motors Corporation subsidiary and provider of digital television entertainment, broadband satellite network, and global video and data broadcasting, from 1992 to December 2003, and retiring as chair in 2003.

... Director of Marriott International, Inc., a major hotel chain, from 1995 to May 2015, and served on the audit, finance, compensation, and excellence committees.

... Director of Nortel Networks Corporation, a global telecommunications company, from January 2005 to August 2009, also served as chair of the board from June 2005.

... Fellow of the American College of Trial Lawyers, and member of the International Society of Barristers.

... Founding chair of the Yale University's Chairmen's Forum; former member of the President's Council on Sustainable Development; and co-chair of the President's Commission on the United States Postal Service.

Education

... Bachelor's degree in engineering sciences from the U.S. Air Force Academy.

... Juris doctor degree from Northwestern University's School of Law.

	<p>John K. Wilson Age 63</p>	<p>Independent Director Since 2003 Audit Committee</p>
<p>Mr. Wilson has an extensive background in finance and accounting, as well as experience with mergers and acquisitions, through his education and work experience at a major accounting firm and his later public utility experience in his 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.</p>		

Career Highlights

... President of Durham Resources, LLC, a privately held financial management company, in Omaha, Nebraska, from 1994 to December 2008; president of Great Plains Energy Corp., a public utility holding company and an affiliate of Durham Resources, LLC, from 1994 to July 1, 2000; and vice president of Great Plains Natural Gas Co., an affiliate company of Durham Resources, LLC, until July 1, 2000.

... Executive director of the Robert B. Daugherty Foundation in Omaha, Nebraska, since January 2010.

... Held positions of 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.

Other Leadership Experience

... Director of HDR, Inc., an international architecture and engineering firm, since December 2008; and director of Tetrad Corporation, a privately held investment company, since April 2010, both located in Omaha, Nebraska.

... Former director of Bridges Investment Fund, Inc., a mutual fund, from April 2003 to April 2008; director of the Greater Omaha Chamber of Commerce from January 2001 through December 2008; member of the advisory board of U.S. Bank NA Omaha from January 2000 to July 2010; and the advisory board of Duncan Aviation, an aircraft service provider, headquartered in Lincoln, Nebraska, from January 2010 to February 2016.

Education and Professional

... Bachelor's degree in business administration, cum laude, from the University of Nebraska † Omaha.

... Certified public accountant, on inactive status.

The board of directors recommends a vote ,forf 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 ,forf a director's election must exceed the number of votes cast ,againstf the director's election. ,Abstentionsf and ,broker non-votesf do not count as votes cast ,forf or ,againstf 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 ,forf 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 ,againstf than votes ,forf 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 on how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

CORPORATE GOVERNANCE AND THE BOARD OF DIRECTORS

Director Independence

The board of directors has adopted guidelines on director independence that are included in our corporate governance guidelines. Our guidelines require that a substantial majority of the board consists of independent directors. In general, the guidelines require that an independent director must have no material relationship with the company directly or indirectly, except as a director. The board determines independence on the basis of the standards specified by the New York Stock Exchange (NYSE), the additional standards referenced in our corporate governance guidelines, and other facts and circumstances the board considers relevant. Based on its review, the board has determined that all directors, except for our chief executive officer Mr. Goodin, have no material relationship with us and are independent.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the non-employee 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:

€ Charitable contributions by the MDU Resources Foundation (Foundation) to the following 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 University of North Dakota Foundation, the University of North Dakota Formula SAE, and the University of Jamestown and its 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.

...Business relationships with entities with which a director is affiliated : (1) Payment of nominal fees to First Interstate Bank, a subsidiary of First Interstate BancSystem, Inc., where Patricia Moss has been a director since May 30, 2017. The fees were for services related to depository accounts at First Interstate Bank. These services were provided in the ordinary course of business and on substantially the same terms as those prevailing at the time for comparable services provided by other bank entities. (2) Mr. Wilson is a member of the board of directors of HDR, Inc., an architectural, engineering, environmental, and consulting firm. The company paid HDR, Inc. or its affiliates for services which were provided in the ordinary course of business and on substantially the same terms prevailing for comparable services from other consulting firms. Mr.€Wilson had no role in securing or promoting the HDR, Inc. services.

The board has also determined that all members of the audit, compensation, and nominating and governance committees of the board are independent in accordance with our guidelines and applicable NYSE and Securities Exchange Act of 1934 rules.

Stockholder Engagement

The company has an active stockholder outreach program.€We believe in providing transparent and timely information to our investors. Each year we routinely engage directly or indirectly with our stockholders, including our top institutional stockholders. During 2017, the company held meetings, conference calls, and webcasts with a diverse mix of stockholders. Throughout the year, we held meetings with eight of the actively managed institutional investors included in our year-end top 30 stockholders. We engage periodically with our index fund investors; however, no direct meetings were held with this investor class in 2017. In our meetings, we discussed a variety of topics with stockholders including longer-term company strategy and our capital expenditure forecast, shorter-term operational and financial updates, and previously announced strategic initiatives. The company also held a telephone conference with a proxy advisory firm to discuss corporate governance and executive compensation practices.

Board Leadership Structure

The board separated the positions of chair of the board and chief executive officer in 2006, and our bylaws and corporate governance guidelines currently require that our chair be independent. The board believes this structure provides balance and is currently in the best interest of the company and its stockholders. Separating these positions allows the chief executive officer to focus on the full-time job of running our business, while allowing the chair of the board to lead the board in its fundamental role of providing advice to and independent oversight of management. The chair meets regularly between board meetings with the chief executive officer and consults with the chief executive officer regarding the board meeting agendas, the quality and flow of information provided to the board, and the effectiveness of the board meeting process. The board believes this split 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 chairparticularly 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 chair is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders, including with respect to risk management as discussed below. An independent chair is in a position to encourage frank and lively discussions, including during regularly scheduled executive sessions consisting of only independent directors, and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. The board believes that having separate positions and having an independent outside director serve as chair is the appropriate leadership structure for the company at this time and demonstrates our commitment to good corporate governance.

Board's Role in Risk Oversight

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, the impact of competition, climate and weather conditions, limitations on our ability to pay dividends, pension plan obligations, cyberattacks or acts of terrorism, and third party liabilities. Management is responsible for identifying material risks, implementing appropriate risk management strategies, and providing information regarding material risks and risk management to the board. 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 for identifying, assessing, and managing risk.

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 chair 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. At least annually, 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 standing 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 NYSE requirements, discusses with the board 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 2017, the board of directors held four regular meetings and two special meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2017. Directors are encouraged to attend our annual meeting of stockholders. All directors attended our 2017 Annual Meeting of Stockholders.

Harry J. Pearce was elected non-employee chair 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. Dennis W. Johnson was elected vice chair of the board on February 15, 2018. The non-employee directors meet in executive session both with and without the chief executive officer at each regularly scheduled quarterly board of directors meeting. All of our non-employee directors are independent, as defined in our corporate governance guidelines and NYSE listing standards.

Proxy Statement

The board has standing audit, compensation, and nominating and governance committees. The table below provides current committee membership.

Name	Audit Committee	Compensation Committee	Nominating and Governance Committee
Thomas Everist		C	
Karen B. Fagg		f	C
Mark A. Hellerstein	f		
A. Bart Holaday	f		f
Dennis W. Johnson	C		
William E. McCracken		f	f
Patricia L. Moss		f	f
John K. Wilson	f		

C - Chair

f - Member

Below is a description of each standing committee of the board. The board has affirmatively determined that each of these standing committees consists entirely of independent directors pursuant to rules established by the NYSE, rules promulgated under the Securities and Exchange Commission (SEC), and the director independence standards established by the board. The board has also determined that each member of the audit committee and the compensation committee is independent under the criteria established by the NYSE and the SEC for audit committee and compensation committee members, as applicable.

Nominating and Governance Committee

Met Four Times in 2017

The nominating and governance committee met four times during 2017. 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
- ... our corporate governance guidelines.

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 in the same manner we consider other nominees. Stockholders who wish to recommend a director candidate may submit recommendations, along with the information set forth in the guidelines, to the nominating and governance committee chair in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650.

Stockholders who wish to 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. Our bylaws are available on our website. See [, Stockholder Proposals, Director Nominations, and Other Items of Business for 2019 Annual Meeting](#) in the section entitled [, Information about the Annual Meeting](#) for further details.

In evaluating director candidates, the committee, in accordance with our corporate governance guidelines, 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, business management, human resources, marketing, operations, public affairs, law, technology, risk management, governance, and operations abroad;
- ... background in publicly traded companies including service on other public company boards of directors;
- ... 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
- ... compliance with applicable law and applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality, stock ownership and trading policies, and other policies and guidelines of the company.

In addition, our bylaws contain requirements that a person must meet to qualify for service as a director.

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.

Audit Committee

Met Eight Times in 2017

The audit committee is a separately-designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

The audit committee met eight times during 2017. 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 SEC rules and are financially literate within meaning of the listing standards of the NYSE. They also meet the independence standard for audit committee members under our director independence guidelines, the NYSE listing standards, and SEC 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 and the code of conduct;
 - „ the independent registered public accounting firm's qualifications and independence;
 - „ the performance of our internal audit function and independent registered public accounting firm;
 - „ management of risk in the audit committee's areas of responsibility; and
- ... arranges for the preparation of and approves the report that SEC rules require we include in our annual proxy statement. See the section entitled , [Audit Committee Report](#) for further information.

During 2017, the compensation committee met seven times. The compensation committee consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the NYSE listing standards and who meet the definitions of outside or non-employee directors for purposes of Section 162(m) of the Internal Revenue Code and Rule 16-b under the Exchange Act. Members of the compensation committee are Thomas Everist, chair, Karen B. Fagg, William E. McCracken, and Patricia L. Moss.

The compensation committee assists the board of directors in fulfilling its responsibilities relating to the company's compensation policy and programs. It has the direct responsibility for determining compensation for our Section 16 officers and for overseeing the company's management of risk in its areas of responsibility. In addition, the compensation committee reviews and recommends any changes to director compensation policies to the board of directors. The authority and responsibility of the compensation committee is outlined in the compensation committee's charter.

The compensation committee uses the analysis and recommendations from outside consultants, the chief executive officer, and the human resources department in making its compensation decisions. The chief executive officer, the vice president-human resources, and the general counsel regularly attend compensation committee meetings. The committee meets in executive session as needed. The processes and procedures for consideration and determination of compensation of the Section 16 officers, as well as the role of our executive officers, are discussed in the [Compensation Discussion and Analysis](#)

The compensation committee has sole authority to retain 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, and the committee is directly responsible for the appointment, compensation, and oversight of the work of such advisers. The compensation 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 by the human resources department in the other years. The compensation committee retained a compensation consultant, Willis Towers Watson, to conduct a competitive analysis on executive compensation in 2016. Prior to retaining an adviser, the compensation committee will consider all factors relevant to ensure the adviser's independence from management. Annually the compensation committee conducts a potential conflicts of interest assessment raised by the work of any compensation consultant and how such conflicts, if any, should be addressed. The compensation committee requested and received information from Willis Towers Watson to assist in its potential conflicts of interest assessment. Based on its review and analysis, the compensation committee determined in 2016 that Willis Towers Watson was independent from management.

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. The compensation committee employed a compensation consultant for an analysis of director compensation in 2017.

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 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, the human resources department identified the principal areas of risk faced by the company that may be affected by our compensation policies and practices, 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 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 company's peer group;
 - „ 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 240% of target) and long-term incentive stock grant awards (200% of 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 for long-term incentive awards with a relative total stockholder return performance measure and mandatory reduction in award if total stockholder return over the performance period is negative;
 - „ use of three-year performance periods for long-term incentive awards to discourage short-term risk-taking;
 - „ substantive annual 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 peer group;
 - „ stock ownership requirements for the board and for executives receiving long-term incentive awards;
 - „ mandatory holding periods for 50% of any net after-tax shares earned under long-term incentive awards; and
 - „ use of independent consultants in establishing pay targets at least biennially.

Stockholder Communications with the Board

Stockholders and other interested parties who wish to contact the board of directors or any individual director, including our non-employee chair 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.

Additional Governance Features

Board and Committee Evaluations

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. The self-evaluations are intended to facilitate a candid assessment and discussion by the board and each committee of its effectiveness as a group in fulfilling its responsibilities, its performance as measured against the corporate governance guidelines, and areas for improvement. The board and committee members are provided with a questionnaire to facilitate discussion. The results of the evaluations are reviewed and discussed in executive sessions of the committees and the board of directors.

Proxy Statement

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 2017, Mr. Everist submitted his resignation in connection with the sale by The Everist Company of its aggregate, concrete, and asphalt production interests. After considering his background, experience on the board, skills and character, and contribution to the company in light of the company's business and structure, the board determined Mr. Everist's resignation should not be accepted.

Majority Voting in Uncontested Director Elections

Our corporate governance guidelines require that in uncontested elections (those where the number of nominees does not exceed the number of directors to be elected), director nominees must receive the affirmative vote of a majority of the votes cast to be elected to our board of directors. Contested director elections (those where the number of director nominees exceeds the number of directors to be elected) are governed by a plurality of the vote of shares present in person or represented by proxy at the meeting.

The board has adopted a director resignation policy for incumbent directors in uncontested elections. Any proposed nominee for re-election as a director shall, before he or she is nominated to serve on the board, tender to the board his or her irrevocable resignation that will be effective, in an uncontested election of directors only, upon (i) such nominee's receipt of a greater number of votes against election than votes for election at our annual meeting of stockholders; and (ii) acceptance of such resignation by the board of directors.

Director Overboarding Policy

Our bylaws and corporate governance guidelines state that a director may not serve on more than three public company boards, including the company's board. Currently, all of our directors are in compliance of this policy.

Board Refreshment

The company regularly evaluates the need for board refreshment. The nominating and governance committee and the board are focused on identifying individuals whose skills and experiences will enable them to make meaningful contributions to shaping the company's business strategy. As part of its consideration of director succession, the nominating and governance committee from time to time reviews, including when considering potential candidates, the appropriate skills and characteristics required of board members. The board believes it is important to consider diversity of skills, expertise, race, ethnicity, gender, age, education, cultural background, and professional experiences in evaluating board candidates for expected contributions to an effective board. Independent directors may not serve on the board beyond the next annual meeting of stockholders after attaining the age of 76. We believe the current retirement age allows us to benefit from long-serving directors, including their industry expertise, institutional knowledge, historical perspective, stability, and comfort with challenging company management, while maintaining our ability to refresh the board through the addition of new members. In connection with our mandatory retirement for directors, A. Bart Holaday will retire as a director at the completion of his current term at the 2018 annual meeting, and two additional directors will retire in 2019.

Prohibitions on Hedging/Pledging Company Stock

The director compensation policy prohibits directors from hedging their ownership of common stock, pledging company stock as collateral for a loan, or holding company stock in an account that is subject to a margin call.

Code of Conduct

We have a code of conduct and ethics, which we refer to as the Leading With Integrity Guide. It applies to all directors, officers, and employees.

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 NYSE listing standards, by posting such information on our website.

Corporate Governance Materials

Stockholders can see our bylaws, corporate governance guidelines, board committee charters, and Leading With Integrity Guide on our website.

Corporate Governance Materials	Website
... Bylaws	http://www.mdu.com/integrity/governance/guidelines-and-bylaws
... Corporate Governance Guidelines	http://www.mdu.com/integrity/governance/guidelines-and-bylaws
... Board Committee Charters for the Audit, Compensation, and Nominating and Governance Committees	http://www.mdu.com/integrity/governance/board-charters-and-committees
... Leading With Integrity Guide	http://www.mdu.com/docs/default-source/governance/leadingwithintegrity.pdf

Related Person Transaction Disclosure

The board of directors' policy for the review of related person transactions is contained in our corporate governance guidelines. The policy provides that the audit committee review 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 direct or indirect 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 is required to be disclosed under the SEC rules, the general counsel furnishes the information to the chair 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.

We had no related person transactions in 2017.

COMPENSATION OF NON-EMPLOYEE DIRECTORS

Director Compensation for 2017

MDU Resources' non-employee directors are compensated for their service according to the MDU Resources Group Inc. Director Compensation Policy. Only one employee, David L. Goodin, the company's president and chief executive officer, serves as a director. Mr. Goodin receives no additional compensation for his service on the board. Director compensation is reviewed annually by the compensation committee with analysis provided by an independent consultant in odd numbered years and analysis prepared by the company's human resources department in even numbered years. Willis Towers Watson provided the director compensation analysis for 2017. The analysis included research on market trends in director compensation as well as a review of director compensation practices of our peer group companies. Based on the analysis, the compensation committee recommended and the board approved at the May 2017 meeting, an increase to the annual base cash retainer from \$65,000 to \$70,000 effective June 1, 2017. In addition, the 2017 annual stock grant for the non-executive chair of the board was increased from \$110,000 to \$145,000. No changes were made to the annual stock grants to other directors or to the additional cash retainers for the non-executive chair of the board or the chairs of the board committees. The following table outlines the compensation paid to our non-employee directors for 2017.

Name	Fees Earned or Paid in Cash (\$)	Stock Awards (\$) ¹	All Other Compensation (\$) ²	Total (\$)
Thomas Everist	77,917	110,000	83	188,000
Karen B. Fagg	77,917	110,000	83	188,000
Mark A. Hellerstein	67,917	110,000	83	178,000
A. Bart Holaday	67,917	110,000	83	178,000
Dennis W. Johnson	82,917	110,000	1,083	194,000
William E. McCracken	67,917	110,000	83	178,000
Patricia L. Moss	67,917	110,000	1,083	179,000
Harry J. Pearce	157,917	145,000	83	303,000
John K. Wilson	67,917 ³	110,000	83	178,000

¹ Each director received an annual retainer of \$110,000 in company common stock except the non-executive chair who received \$145,000 in company common stock pursuant to the MDU Resources Group, Inc. Non-Employee Director Stock Compensation Plan or the Non-Employee Director Long-Term Incentive Compensation Plan. The amount shown for each director, except Mr. Pearce, represents the aggregate grant date fair value of 4,091 shares of MDU Resources Group, Inc. common stock. The amount shown for Mr. Pearce who serves as our non-executive chair of the board represents the aggregate grant date fair value of 5,393 shares of MDU Resources Group, Inc. common stock. All shares are measured in accordance with Financial Accounting Standards Board (FASB) 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 of November 21, 2017, which was \$26.88 per share. The amount paid in cash for fractional shares was \$21.65 to each director and \$19.98 to our non-executive chair of the board and is included in the amount reported in the stock awards column to this table. As of December 31, 2017, there are no outstanding stock awards or options associated with the Non-Employee Director Stock Compensation Plan or the Non-Employee Director Long-Term Incentive Compensation Plan.

² Includes group life insurance premiums and charitable donations made on behalf of the director as applicable.

³ Mr. Wilson elected to receive shares of our common stock in lieu of his cash retainer pursuant to the Director Compensation Policy and the Non-Employee Director Long-Term Incentive Compensation Plan. The amount shown includes 2,451 shares of our common stock purchased on December 6, 2017, at \$27.70 per share.

The following table shows the cash and stock retainers payable to our non-employee directors.

	Effective through May 31, 2017	Effective June 1, 2017
Base Cash Retainer	\$ 65,000	\$ 70,000
Additional Cash Retainers:		
Non-Executive Chair	90,000	90,000
Audit Committee Chair	15,000	15,000
Compensation Committee Chair	10,000	10,000
Nominating and Governance Committee Chair	10,000	10,000
Annual Stock Grant - Directors	110,000	110,000
Annual Stock Grant - Non-Executive Chair	145,000	

¹ The annual stock grant is a grant of shares equal in value to \$110,000.

² The annual stock grant is a grant of shares equal in value to \$145,000.

There are no meeting fees paid to directors.

Other Compensation

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 \$82.80. Directors who contribute to the company's Good Government Fund may designate up to two charities to receive a matching donation from the MDU Resources Foundation based on their contributions to the fund. Directors are reimbursed for all reasonable travel expenses, including spousal expenses in connection with attendance at meetings of the board and its committees. Perquisites, if any, were below the disclosure threshold in 2017.

Deferral of Compensation

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.

Post-Retirement

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.

Stock Ownership Policy

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 are considered in ownership calculations as is 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. All directors are in compliance with the stock ownership policy. For further details on our director's stock ownership, see the section entitled [Security Ownership](#).

SECURITY OWNERSHIP

Security Ownership Table

The table below sets forth the number of shares of our common stock that each director and each nominee for director, each current named executive officer, and all directors and executive officers as a group owned beneficially as of February 28, 2018. Unless otherwise indicated, each person has sole investment and voting power (or share such power with his or her spouse) of the shares noted.

Name	Common Shares Beneficially Owned	Percent of Class	Post-Retirement and/or Deferred Director Fees Held as Phantom Stock
David C. Barney	24,604 ^{3,4}	*	‡
Thomas Everist	857,549	*	33,952
Karen B. Fagg	67,086	*	‡
David L. Goodin	176,336 ³	*	‡
Mark A. Hellerstein	19,857	*	11,485
A. Bart Holaday	65,002	*	11,485
Dennis W. Johnson	86,248 ⁵	*	‡
Nicole A. Kivisto	41,196 ^{3,6}	*	‡
William E. McCracken	19,857	*	‡
Patricia L. Moss	78,525	*	‡
Harry J. Pearce	241,278	*	55,824
Jeffrey S. Thiede	21,719 ³	*	‡
Jason L. Vollmer	6,019 ³	*	‡
John K. Wilson	125,458	*	‡
All directors and executive officers as a group (19 in number)	1,906,649	0.98 %	112,746

* Less than one percent of the class. Percent of class is calculated based on 195,304,376 outstanding shares as of February 28, 2018.

¹ The table includes the ownership of all current directors, director nominees, current named executive officers, and other executive officers of the company without naming them. The table does not include stock ownership information for Mr. Martin Fritz who resigned effective May 23, 2017; Mr. Dennis Haider who retired on June 12, 2017; and Mr. Doran Schwartz who resigned effective September 29, 2017.

² Reported shares are not included in the 'Common Shares Beneficially Owned' column. Phantom stock includes the value of post-retirement benefits for directors on the board prior to May 2001 when the post-retirement income plan for directors was terminated and the value of any cash compensation deferred pursuant to the Deferred Compensation Plan for Directors. Post-retirement and 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.

³ Includes full shares allocated to the officer's account in our 401(k) retirement plan.

⁴ The total includes 687 shares owned by Mr. Barney's spouse.

⁵ Mr. Johnson disclaims all beneficial ownership of the 163 shares owned by his spouse.

⁶ The total includes 531 shares owned by Ms. Kivisto's spouse.

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.

Based on information from company records or filings with the SEC, the table below shows information regarding the beneficial ownership 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	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	21,720,106 ¹	11.12%
Common Stock	BlackRock, Inc. 55 East 52nd Street New York, NY 10055	16,450,816 ²	8.40%
Common Stock	Parnassus Investments 1 Market Street, Suite 1600 San Francisco, CA 94105	15,215,391 ³	7.79%
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street	11,669,385 ⁴	5.97%

¹ Based solely on the Schedule 13G, Amendment No. 6, filed on February 9, 2018, The Vanguard Group reported sole dispositive power with respect to 21,608,438 shares, shared dispositive power with respect to 111,668 shares, sole voting power with respect to 102,120 shares, and shared voting power with respect to 22,519 shares. These shares include 87,969 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 36,670 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.

² Based solely on the Schedule 13G, Amendment No. 8, filed on January 25, 2018, BlackRock, Inc. reported sole voting power with respect to 15,513,498 shares and sole dispositive power with respect to 16,450,816 shares as the parent holding company or control person of BlackRock Life Limited, BlackRock Advisors, LLC, BlackRock (Netherlands) B.V., BlackRock Institutional Trust Company, National Association, BlackRock Asset Management Ireland Limited, BlackRock Financial Management, Inc., BlackRock Japan Co., Ltd., BlackRock Asset Management Schweiz AG, BlackRock Investment Management, LLC, BlackRock Investment Management (UK) Limited, BlackRock Asset Management Canada Limited, BlackRock Investment Management (Australia) Limited, BlackRock Advisors (UK) Limited, BlackRock Fund Advisors, BlackRock Asset Management North Asia Limited, and BlackRock Fund Managers Ltd.

³ Based solely on the Schedule 13G, Amendment No. 3, filed on February 12, 2018, Parnassus Investments reported sole voting and dispositive power with respect to 15,215,391 shares.

⁴ Based solely on the Schedule 13G, filed on February 14, 2018, State Street Corporation reported shared voting and dispositive power with respect to 11,669,385 shares as the parent holding company or control person of State Street Bank and Trust Company, SSGA Funds Management, Inc., State Street Global Advisors Trust Company, State Street Global Advisors Asia LTD, State Street Global Advisors Singapore LTD., State Street Global Advisors Limited, and State Street Global Advisors GmbH.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934, as amended, requires officers, directors, and holders of more than 10% of our common stock file reports of their trading in our equity securities with the SEC. 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 2017, or written representations that no Forms 5 were required, we believe that all such reports were timely filed.

EXECUTIVE COMPENSATION

ITEM 2. ADVISORY VOTE TO APPROVE THE COMPENSATION PAID TO 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 an 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 60% of our 2017 total target direct compensation for our current named executive officers in the form of performance-based incentive compensation;
- ... 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 align executive compensation and performance by using annual performance incentives based on criteria that are important to stockholder value, including earnings, earnings per share, and return on invested capital; and
- ... we align executive compensation and performance by using long-term performance incentives based on total stockholder return relative to our 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 2017. Accordingly, the following resolution is submitted for stockholder vote at the 2018 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.^f

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. We intend to hold this advisory vote every year until at least the next stockholder advisory vote on the frequency of this vote.

The board of directors recommends a vote ,for^f the approval, on a non-binding advisory basis, of the compensation of the company's 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.

INFORMATION CONCERNING EXECUTIVE OFFICERS

At the first 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, 2017, present corporate positions, and business experience during the past five years, is as follows:

Name	Age	Present Corporate Position and Business Experience
David L. Goodin	56	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 the section entitled Item 1. Election of Directors
David C. Barney	62	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013, and president effective January 1, 2012.
Stephanie A. Barth	45	Ms. Barth was elected vice president, chief accounting officer and controller effective September 30, 2017. Prior to that, she was controller of the company effective May 30, 2016, vice president, treasurer and chief accounting officer of WBI Holdings, Inc. effective January 1, 2015, controller of WBI Holdings, Inc. effective September 30, 2013, and director financial planning & reporting of WBI Holdings, Inc. effective December 22, 2008.
Trevor J. Hastings	44	Mr. Hastings was elected president and chief executive officer of WBI Holdings, Inc. effective October 16, 2017. Prior to that, he was vice president-business development and operations support of Knife River Corporation effective January 11, 2012.
Anne M. Jones	54	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, and director of human resources for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective June 2008.
Nicole A. Kivisto	44	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, and vice president, controller and chief accounting officer for the company effective February 17, 2010.
Daniel S. Kuntz	64	Mr. Kuntz was elected vice president, general counsel and secretary effective January 1, 2017. Prior to that, he was general counsel and secretary effective January 9, 2016, associate general counsel effective April 1, 2007, and assistant secretary effective August 17, 2007.
Margaret (Peggy) A. Link	51	Ms. Link was elected vice president and chief information officer effective December 1, 2017. Prior to that, she was chief information officer effective January 1, 2016, assistant vice president-technology and cybersecurity officer effective January 1, 2015, and director shared IT services effective June 2, 2009.
Jeffrey S. Thiede	55	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.
Jason L. Vollmer	40	Mr. Vollmer was elected vice president, chief financial officer and treasurer effective September 30, 2017. Prior to that, he was vice president, chief accounting officer and treasurer effective March 19, 2016, treasurer and director of cash and risk management effective November 29, 2014, manager of treasury services and risk management effective June 30, 2014, and manager of treasury services, cash and risk management effective April 11, 2011.

COMPENSATION DISCUSSION AND ANALYSIS

The Compensation Discussion and Analysis describes how our named executive officers were compensated for 2017 and how their 2017 compensation aligns with our pay for performance philosophy. It also describes the oversight of the compensation committee and the rationale and processes used to determine the 2017 compensation of our named executive officers including the objectives and specific elements of our compensation program.

The Compensation Discussion and Analysis may contain statements regarding corporate performance targets and goals. The 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.

Our Named Executive Officers for 2017 were:

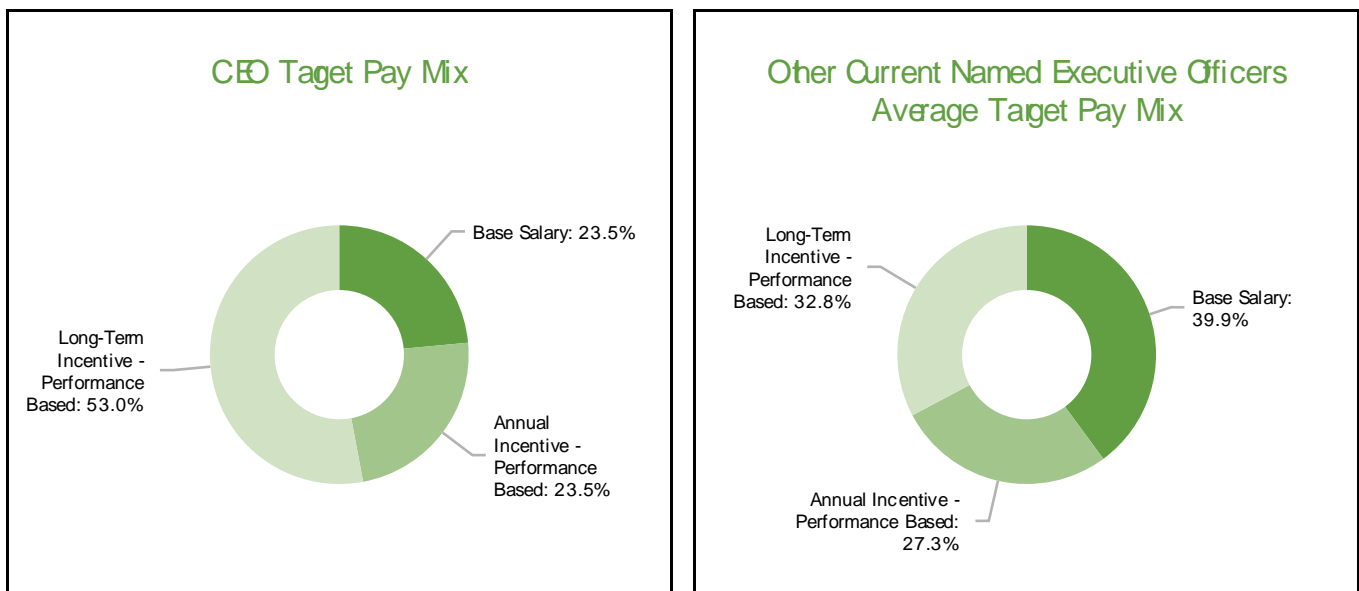
- David L. Goodin President and Chief Executive Officer (CEO)
- Jason L. Vollmer Vice President, Chief Financial Officer (CFO) and Treasurer
- David C. Barney President and Chief Executive Officer - Construction Materials and Contracting Segment
- Jeffrey S. Thiede President and Chief Executive Officer - Construction Services Segment
- Nicole A. Kivisto President and Chief Executive Officer - Electric and Natural Gas Distribution Segments
- Doran N. Schwartz Former Vice President and Chief Financial Officer

Mr. Schwartz resigned his position effective September 29, 2017.

Executive Summary

Pay for Performance

To ensure management's interests are aligned with those of our stockholders and the performance of the company, over 75% of the CEO's target compensation and over 60% of the other current named executive officers' target compensation is dependent on the achievement of company performance targets. The charts below show the target pay mix for the CEO and average target pay mix of the other current named executive officers, including base salary and the annual and long-term at-risk performance incentives.



Annual Base Salary

We provide our executive officers with base salary at a sufficient level to attract, recruit, and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities. Consistent with our compensation philosophy of linking pay to performance, our executives receive a relative smaller percentage of their overall target compensation in the form of base salary. In establishing base salaries, the compensation committee considers each executive's individual performance, the scope and complexities of their responsibilities, internal equity, and whether the executive's base salary is competitive as measured against the base salaries of similarly situated executives in our peer group and market compensation data.

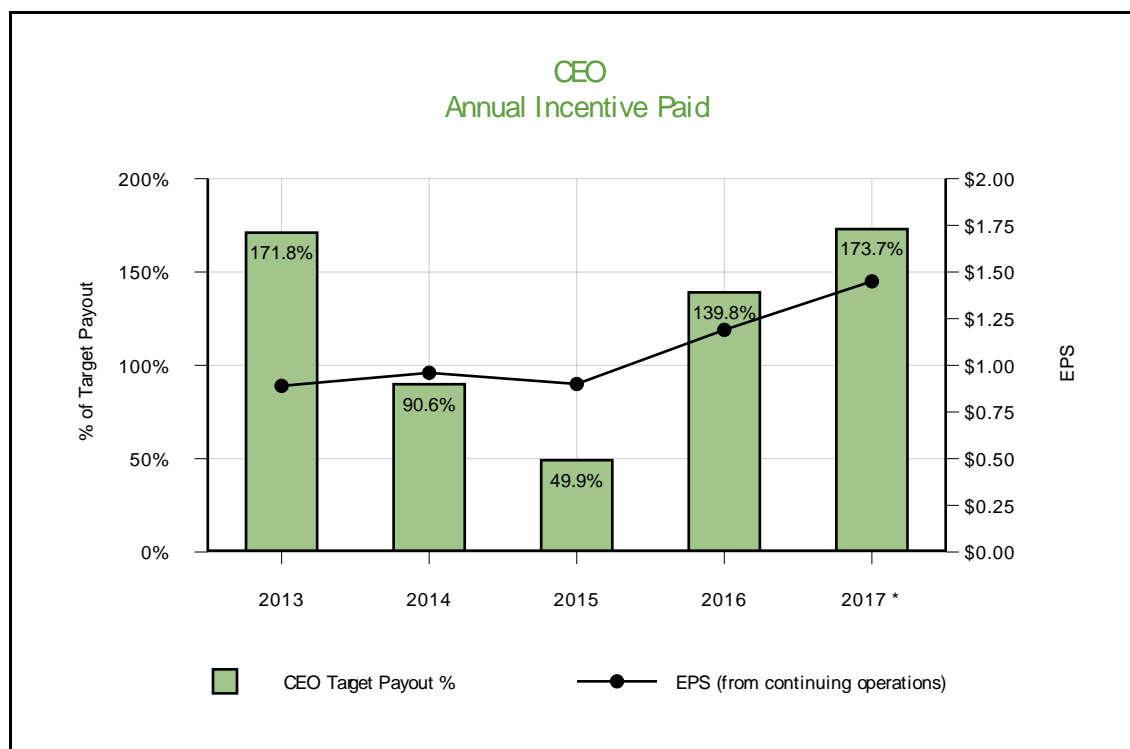
Annual Cash Incentive Awards

Annual cash incentive awards for our executive officers are linked to performance by rewarding achievement of operational and financial goals and ensuring our executive officers are focused and accountable for our growth and profitability. The design of the annual cash incentive award opportunities for 2017 was the same as the design used in 2016. Each executive is assigned a target annual incentive award based on a percentage of the executive's base salary. The actual annual cash incentive realized is determined by multiplying the target award by the payout percentage associated with achievement of the executive's performance measures.

The compensation committee selected specific business segment financial performance measures for each business segment executive which represented 80% of their annual award opportunity. The other 20% of the business segment executive's annual award opportunity was based on the achievement of overall company earnings per share (EPS). These measures incentivize our business segment executives to focus on the success and performance of their business segment while keeping the overall success of the company in mind.

The annual cash incentive award for corporate executives (including our CEO and CFO) is based on the achievement of each business segment's performance measures and weighted by each business segment's invested capital relative to overall company invested capital. The executive's target award is multiplied by the sum of the weighted achievement percentages for the business segments to derive the executive's realized annual award. This incentivizes the corporate executives to assist the business segments in their success while still emphasizing overall company performance. See the "Annual Incentives" section within this Compensation Discussion and Analysis for further details on our company's annual cash incentive program.

The following chart shows the annual incentive payout of target realized by our CEO with a comparison to earnings per share from continuing operations for the last five years and demonstrates the alignment between our financial performance and realized annual cash incentive compensation.

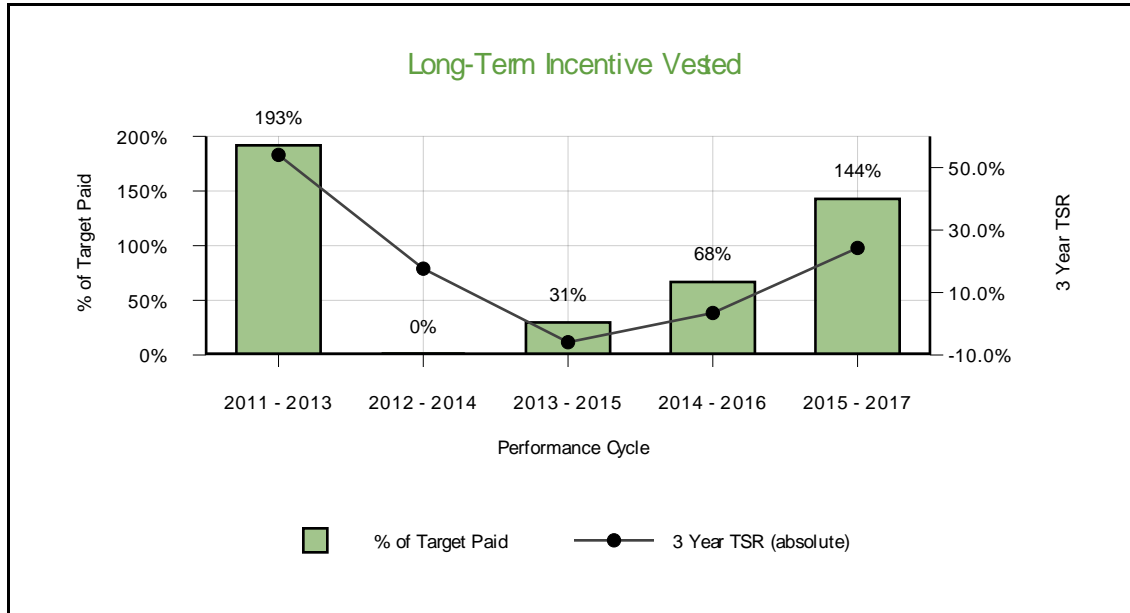


* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of \$1.45 per share which included a benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act, which was signed into law December 22, 2017. The earnings per share absent the federal Tax Cuts and Jobs Act benefit is \$1.25.

Proxy Statement

Long-Term Equity-Based Incentive Awards

Our compensation committee grants long-term incentives to our executives in the form of performance shares which vest into company stock plus dividend equivalents after a three-year period only if certain performance measures are achieved. The performance measure used for our long-term incentives is based on our company's total stockholder return (TSR) in comparison to that of our peers measured over a three-year period. The following chart depicts the actual vesting percentage for the last five performance cycles and demonstrates the alignment between total return to our stockholders and our realized long-term incentive compensation.



See the "Long-Term Incentives" section within this Compensation Discussion and Analysis for further details on the company's long-term incentive program.

With the majority of our executive officers' compensation dependent on the achievement of performance measures set by the compensation committee, we believe there is substantial alignment between executive pay and the company's performance.

Stockholder Advisory Vote ("Say on Pay")

At our 2017 Annual Meeting of Stockholders, 95.8% of the votes cast on the "Say on Pay" proposal approved the compensation of our named executive officers. The compensation committee viewed the 2017 vote as an expression of the stockholders' general satisfaction with the company's executive compensation programs. The compensation committee reviewed and considered the 2017 vote on "Say on Pay" in setting compensation for 2018 by continuing to link performance-based annual and long-term incentives to company financial performance and shareholder value.

Compensation Practices

Our practices and policies ensure alignment between the interests of our stockholders and our executives as well as effective compensation governance.

What We Do

Pay for Performance Annual and long-term award incentives tied to performance measures set by the compensation committee comprise the largest portion of executive compensation.

Independent Compensation Committee - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.

Independent Compensation Consultant - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.

Competitive Compensation Executive compensation reflects the executive's performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, the business segment's economic environment, and the actual performance of the overall company or the executive's business segment.

Annual Cash Incentive Payment of annual cash incentive awards are based on business segment and overall company achievement against pre-established financial measures.

Long-Term Equity Incentive - The long-term equity incentive represents 53% of our CEO's and approximately 33% of our other current named executive officer's target compensation in the form of performance shares which may be earned based on relative TSR performance measured over a three-year period.

Annual Compensation Risk Analysis - We regularly analyze the risks related to our compensation programs and conduct an annual broad risk assessment.

Stock Ownership and Retention Requirements - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. The executive officers must also retain at least 50% of the net after tax shares of stock vested through the long-term incentive plan for the earlier of two years or until termination of employment.

Clawback Policy - If the company's audited financial statements are restated, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

Performance Share Awards Purchased at Market Performance share awards are purchased on the market to avoid shareholder dilution by issuing authorized but unissued shares.

What We Don't Do

Stock Options The company does not use stock options as a form of incentive compensation.

Employment Agreements Current executives do not have employment agreements entitling them to specific payments upon a change of control of the company.

Perquisites - Executives do not receive perquisites which materially differ from those available to employees in general.

Tax Gross-Ups - Executive officers do not receive tax gross-ups on any compensation.

Hedge Stock Executives and directors are not allowed to hedge company securities.

Pledge Stock Executives and directors are not allowed to pledge company securities in margin accounts or as collateral for loans.

No Dividends or Dividend Equivalents on Unvested Shares - We do not provide for payment of dividends or dividend equivalents on unvested share awards.

2017 Compensation Framework

Objectives of our Compensation Program

We have a written executive compensation policy for our executive 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 for growth in enterprise value over the long-term;
- ... provide a competitive compensation package relative to industry-specific and general industry comparisons and internal equity;
- ... 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
- ... ensure that compensation programs do not encourage or reward excessive or imprudent risk taking.

Compensation Decision Process for 2017

For 2017, the compensation committee made recommendations to the board of directors regarding compensation of all executive officers, and the board of directors then approved the recommendations. The CEO's role in the process includes the assessment of executive officer performance and recommending base salaries for the executive officers other than himself. The CEO attended all the compensation committee meetings but was not present during discussions of his compensation. The compensation committee established and approved base salaries and performance measures for the annual and long-term incentive compensation for 2017. They also certified the achievement of performance measures associated with annual and long-term incentive compensation.

At least every two years, the compensation committee hires an independent consulting firm to assess and recommend competitive pay levels, including base salaries and incentive compensation associated with executive officer positions. Typically the consulting firm conducts its analysis in even numbered years. In odd numbered years, the assessment is performed by the company's human resources department using a variety of industry specific sources. In August 2016, Willis Towers Watson prepared the analysis of and provided recommendations for the 2017 compensation structure.

Components of Compensation

The components of our executive officer's compensation are selected to drive financial and operational results as well as align the executive officer's interests with those of our stockholders. The components of our executive compensation include:

Component	Payments	Purpose	How Determined	How it Links to Performance
Base Salary	Assured	Provides sufficient, regularly paid income to recruit and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities.	Based on recommendation from the CEO for executives other than himself and analysis of peer company and industry compensation information.	Base salary is a means to attract and retain talented executives capable of driving success and performance.
Annual Cash Incentive	Performance Based At Risk	Provides an opportunity to earn annual incentive compensation to ensure focus on annual financial and operating results and to be competitive from a total remuneration standpoint.	Annual cash incentives are calculated as a percentage of base salary with payout based on the achievement of multiple performance measures established by the compensation committee.	Annual incentive performance measures are tied to the achievement of financial goals aimed to drive the success of the company.
Performance Shares	Performance Based At Risk	Provides an opportunity to earn long-term compensation to ensure focus on stockholder return and to be competitive from a total remuneration standpoint.	Performance share award opportunities are calculated as a percentage of base salary with vesting based on the company's total stockholder return over a three-year period in comparison to the company's peer group.	Fosters ownership in company stock and aligns the executive's interests with those of the stockholder in increasing stockholder value.

Allocation of Total Target Compensation for 2017

Total target compensation consists of base salary plus target annual and long-term incentive compensation. Performance-based compensation accounts for over 75% of our CEO's and on average approximately 60% of our other current named executive officers' total target compensation. Incentive compensation, which consists of annual cash incentive and three-year performance share award opportunities, comprises the largest 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 dependent upon our performance;
- ... incentive compensation helps ensure focus on performance measures that are aligned with our overall strategy; and
- ... the interests of the named executive officers are aligned with those of stockholders by making a significant portion of their target compensation contingent upon results beneficial to stockholders.

To foster and reward long-term growth, the compensation committee generally allocates a higher percentage of total target compensation to the target long-term incentive than to the target annual incentive for our higher level executives because they are in a better position to influence our long-term performance. The long-term incentive awards, if earned by achieving performance measures, are paid in company common stock. These awards, combined with our stock retention requirements and our stock ownership policy, promote ownership of our stock by the executive officers. The compensation committee believes, as stockholders, the executive officers will be motivated to deliver results that build value for all stockholders over the long term.

Peer Group

The compensation committee evaluates the company's compensation plan and its performance relative to a group of peer companies in determining compensation and the vesting of long-term incentive compensation. The companies included in our peer group are evaluated every year and are selected to be representative of the industries in which we operate. Questar was removed from our peer group for 2017 due to its acquisition by Dominion Energy. The following chart depicts the companies included in our 2017 peer group.

2017 Peer Companies

Regulated Energy Delivery	Construction Materials and Services
ALLETE, Inc.	EMCOR Group, Inc.
Alliant Energy Corporation	Granite Construction Incorporated
Atmos Energy Corporation	IES Holdings, Inc.
Avista Corporation	Martin Marietta Materials, Inc.
Black Hills Corporation	MYR Group, Inc.
IDACORP, Inc.	Quanta Services, Inc.
National Fuel Gas Company	Sterling Construction Company, Inc.
Northwest Natural Gas Company	U.S. Concrete, Inc.
NorthWestern Corporation	Vulcan Materials Company
Vectren Corporation	

2017 Compensation for Our Named Executive Officers

2017 Salary and Incentive Targets

At its November 2016 meeting, the compensation committee considered the company's financial performance, return on invested capital for the company and individual business segments, the compensation report prepared and presented by Willis Towers Watson at its August 2016 meeting, executive performance appraisals, each executive's tenure in position, and input and recommendations from the CEO and human resources department, in approving base salaries for the named executive officers for 2017. Mr. Goodin was not present during the portion of the meeting where the compensation committee discussed and approved the president and CEO base salary for 2017. At its February 2017 meeting, the compensation committee approved the annual and long-term incentive opportunities for our named executive officers. The following information relates to each named executive officer's base salary, target cash annual incentive, target long-term incentive, and total direct compensation:

David L. Goodin	2017 (\$)	Compensation Component as a % of Base Salary
Base Salary	792,750	n/a
Target Annual Incentive Opportunity	792,750	100 %
Target Long-Term Incentive Opportunity	1,783,688	225 %
Target Total Potential Direct Compensation	3,369,188	425 %
<p>The Compensation Committee increased Mr. Goodin's base salary by 5% for 2017 based on his and the company's performance in 2016. No changes were made to Mr. Goodin's annual or long-term incentive targets as a percentage of base salary for 2017.</p>		

Jason L. Vollmer	2017 (\$)	Compensation Component as a % of Base Salary
Base Salary	350,000	n/a
Target Annual Incentive Opportunity	132,981	38 %
Target Long-Term Incentive Opportunity	112,750	32 %
Target Total Potential Direct Compensation	595,731	170 %
<p>Upon his promotion on September 30, 2017, Mr. Vollmer's base salary was set at \$350,000 with an annual incentive target of 65% of his base salary. For 2017, Mr. Vollmer's base salary and annual cash incentive were prorated for the period of time in his position. Due to the timing of Mr. Vollmer's promotion, the target long-term incentive opportunity for 2017 was not changed and is based on 50% of Mr. Vollmer's base salary prior to promotion.</p>		

David C. Barney	2017 (\$)	Compensation Component as a % of Base Salary
Base Salary	427,140	n/a
Target Annual Incentive Opportunity	320,355	75 %
Target Long-Term Incentive Opportunity	384,426	90 %
Target Total Potential Direct Compensation	1,131,921	265 %
<p>Mr. Barney received a 5% increase in base salary for 2017 due to his success in management of the construction materials and contracting segment to a record year of earnings in 2016. For 2017, the compensation committee maintained Mr. Barney's target annual incentive opportunity at 75% of his base salary but increased his long-term incentive opportunity from 80% to 90% to be consistent with the other business unit presidents and to be competitive with construction industry peers.</p>		

Jeffrey S. Thiede	2017 (\$)	Compensation Component as a % of Base Salary
Base Salary	437,750	n/a
Target Annual Incentive Opportunity	328,313	75 %
Target Long-Term Incentive Opportunity	393,975	90 %
Target Total Potential Direct Compensation	1,160,038	265 %
<p>Mr. Thiede received a 3% increase in his base salary for 2017 in recognition of his successful management of the construction services segment during 2016. For 2017, the compensation committee maintained Mr. Thiede's target annual cash incentive opportunity at 75% of base salary but increased his long-term incentive opportunity from 80% to 90% to be consistent with the other business unit presidents and to be consistent with construction industry peers.</p>		

Nicole A. Kivisto	2017 (\$)	Compensation Component as a % of Base Salary
Base Salary	378,000	n/a
Target Annual Incentive Opportunity	245,700	65%
Target Long-Term Incentive Opportunity	340,200	90%
Target Total Potential Direct Compensation	963,900	255%
Ms. Kivisto received a base salary increase of 18% reflecting her success and management of the electric and natural gas distribution segments in 2016, her tenure within her position, and internal equity. No changes were made to her target annual and long-term incentive opportunities as a percentage of base salary for 2017.		

Doran N. Schwartz	2017 (\$)	Compensation Component as a % of Base Salary
Base Salary	391,500	n/a
Target Annual Incentive Opportunity	254,475	65%
Target Long-Term Incentive Opportunity	352,350	90%
Target Total Potential Direct Compensation	998,325	255%
Mr. Schwartz received a 3% increase in base salary to reflect his successful management of the accounting and finance areas of the company during 2016. No changes were made to his target annual or long-term incentive opportunities as a percentage of base salary for 2017. Mr. Schwartz resigned his position on September 29, 2017, and as a result he was not eligible to receive an annual cash or long-term incentive award payment for 2017.		

Annual Incentives

Annual incentive awards are determined for business segment executives by the achievement of specific performance measures selected by the compensation committee including financial performance measures specific to each business segment and a performance measure based on overall company EPS. For corporate executives, annual incentive awards are determined as the sum of the weighted portion of the percentage award payout of each business segment based upon achievement of its performance measures and weighted by the business segment's invested capital relative to the overall company invested capital. Through this, our business segment executives are incentivized to primarily focus on the success and performance of their business segment while keeping the overall financial success of the company in mind, whereas our corporate executives are incentivized to assist in the success and performance of all lines of business.

The compensation committee considered and selected financial performance measures to ensure that compensation to the executives reflects the success of their respective business segments and the company as well as value provided to our stockholders. Each business segment president's performance measures include a corporate earnings per share performance measure representing 20% of the target award opportunity and business segment financial performance measures representing 80% of the award opportunity. The following annual incentive performance measures for 2017 were adopted by the compensation committee for the business segment presidents (exclusive of the MDU Resources Group, Inc. corporate executive officers) at the February 2017 meeting:

Proxy Statement

Measure	Applies to	Purpose	Measurement	Target	Weight	How Target was Selected
MDU Resources Diluted Adjusted Earnings per Share (EPS)	All the Business Segment Presidents	EPS is a generally accepted accounting principle (GAAP) measurement and is a key driver of stockholder return. This goal applies to the presidents of all business segments to engage them as members of the company's Management Policy Committee in the overall success of the company.	GAAP EPS (diluted) before discontinued operations plus any operations discontinued after December 31, 2016 and adjusted to remove: <ul style="list-style-type: none"> - the effect on earnings from losses on asset sales/dispositions pre-approved by the board, - the effect on earnings from withdrawal liabilities relating to multi-employer pension plans, - the effect on earnings from any acquisitions, mergers, or divestitures initiated in 2017, and - the effect on earnings from amendments to the United States tax code adopted in 2017. 	\$1.15	20%	Target reflects anticipated EPS performance within the range of guidance for 2017 while also being higher than 2016 target and actual results.
Return on Invested Capital (ROIC)	Electric and Natural Gas Distribution Segments President	Provides a measure of how effective the business segment uses its capital and generates a return from its capital. These segments are primarily regulated entities requiring significant capital investment. ROIC is important in providing a return to our stockholders.	Business segment earnings, without regard to after tax interest expense and preferred stock dividends divided by the business segment's average capitalization for the calendar year.	4.7%	40%	Target reflects returns necessary to achieve the segment's risk adjusted capital costs while also being higher than 2016 target and actual results in expectation of regulatory rate relief for major capital investments made in 2015.
	Pipeline and Midstream Segment President			6.0%	40%	Target reflects returns necessary to achieve the segment's risk adjusted capital costs while also being higher than the 2016 target but lower than the 2016 actual results in recognition of lower expected revenues in 2017 resulting from the sale of the Pronghorn gas processing plant.
Business Segment Earnings	Electric and Natural Gas Distribution Segments President	Provides a measure of financial performance.	GAAP business segment earnings adjusted to exclude: <ul style="list-style-type: none"> - the effect on earnings from losses on asset sales/dispositions pre-approved by the board, - the effect on earnings from withdrawal liabilities related to multi-employer pension plans, - the effect on earnings from any acquisitions, mergers, or divestitures initiated in 2017, and - the effect on earnings from amendments to the United States tax code adopted in 2017. 	\$77.7 million	40%	Target reflects earnings necessary to achieve the segment's risk adjusted capital costs while also being higher than 2016 target and actual results.
	Pipeline and Midstream Segment President			\$18.0 million	40%	Target reflects earnings necessary to achieve the segment's risk adjusted capital costs while lower than 2016 target and actual results in recognition of lower expected earnings in 2017 resulting from the sale of the Pronghorn gas processing plant.
	Construction Materials and Contracting Segment President			\$63.6 million	80%	Target reflects earnings necessary to achieve the segment's risk adjusted capital costs and higher than 2016 target but lower than 2016 actual results in recognition that factors contributing to the segment's record success in 2015 and 2016, such as favorable weather, may not be repeated in 2017.
	Construction Services Segment President			\$28.1 million	80%	Target reflects earnings above that necessary to achieve the segment's risk adjusted capital costs but lower than 2016 target and actual earnings in recognition of the segment's expectation for growth but offset by the loss of earnings from solar generation projects completed in 2016.

Actual performance results are compared to target performance measures to arrive at a percent of target achieved. The percent of target achieved is translated into a payout percentage of the target award opportunity with 100% achievement of a performance measure corresponding to a payout equal to the target annual award opportunity. Receipt of a payout requires threshold achievement of a performance measure which varies by business segment. For the company EPS performance measure, as well as the regulated energy delivery companies' business segment performance measures, threshold payout requires achievement of 85% of the target performance measure which results in a payout of 25% of the award opportunity. For the construction materials and contracting and construction services business segments' performance measures, threshold payout requires earnings of an amount necessary to achieve a return on invested capital equal to the segment's risk adjusted capital costs. Maximum payouts also vary by business segment. For the company EPS performance measure, as well as the regulated energy delivery companies' business segment performance measures, maximum payout of 200% of the award opportunity is received if the percent of target achieved is 115% or greater. For the construction materials and contracting business segment performance measure, payout levels of 200%, and a maximum payout level of 250%, is received if earnings achieve returns on invested capital of 11.9% and 12.9%, respectively. For the construction services business segment performance measure, payout levels of 200%, and a maximum payout level of 250%, is received if earnings achieve returns on invested capital of 11.5% and 14.9%, respectively. Results achieved between the payout levels are calculated using linear interpolation.

2017 Annual Performance Incentive Results

The following table shows the 2017 performance measure results, percent of target achieved based on those results, and the associated payout percentages:

Business Segment	Performance Measure	Result	Percent of Performance Measure Achieved	Percent of Award Opportunity Payout	Weight	Weighted Award Opportunity Payout %
All Business Segments	Earnings per Share	\$1.26	109.6 %	163.8 %	20%	32.8 %
Electric and Natural Gas Distribution Segments	Earnings	\$88.0 million	113.3%	188.5%	40%	75.4%
	ROIC	5.2%	110.6%	170.9%	40%	68.4%
Pipeline and Midstream Segment	Earnings	\$20.6 million	114.6%	197.8%	40%	79.1%
	ROIC	7.0%	116.7%	200.0%	40%	80.0%
Construction Materials and Contracting Segment	Earnings	\$81.5 million	128.2 %	147.7 %	80%	118.2 %
Construction Services Segment	Earnings	\$49.0 million	174.6 %	242.1 %	80%	193.7 %

For our corporate named executive officers, namely Messrs. Goodin and Vollmer, the compensation committee continued to base the payout of the annual cash incentives on the achievement of performance measures at the business segments weighted by each business segment's average invested capital relative to the company's total invested capital. The compensation committee believes this approach provides alignment between our corporate executives and business segment performance. Messrs. Goodin's and Vollmer's 2017 annual cash incentives were earned at 173.7% of the target award opportunity based on the following proportional weighted sum of the annual business segment payouts:

Business Segment	Column A Business Segment Award Opportunity Payout	Column B Percentage of Average Invested Capital	Column A x Column B
Electric and Natural Gas Distribution	176.6 %	60.3 %	106.5 %
Pipeline and Midstream	191.9 %	8.6 %	16.5 %
Construction Materials and Contracting	151.0 %	22.0 %	33.2 %
Construction Services	192.8 %	9.1 %	17.5 %
Total Payout Percentage			173.7 %

¹ For purposes of calculating the annual incentive payouts for corporate executives, the award opportunity payout associated with the earnings performance measure for the construction services segment was limited to 200%, which resulted in an unweighted construction services segment award opportunity payout percentage of 192.8% whereas the construction services segment president achieved an award opportunity payout of 226.5%.

Proxy Statement

Based on the achievement of the performance targets, the named executive officers received the following 2017 annual incentive compensation:

Name	Target Annual Incentive (\$)	Annual Incentive Earned	
		Payout as a % of Target (%)	Amount (\$)
David L. Goodin	792,750	173.7	1,377,007
Jason L. Vollmer ¹	132,981	173.7	230,988
David C. Barney	320,355	151.0	483,736
Jeffrey S. Thiede	328,313	226.5	743,629
Nicole A. Kivisto	245,700	176.6	433,906
Doran N. Schwartz ²	254,475	‡	‡

¹ Mr. Vollmer's target annual incentive is prorated based on three months in his new position as vice president, CFO and treasurer and nine months in his former position as vice president, chief accounting officer and treasurer.

² Mr. Schwartz resigned effective September 29, 2017. As a result, he was not eligible for an annual incentive payment.

Long-Term Incentives

As in the past, the compensation committee used performance shares as the form of long-term incentive compensation for 2017 and established the company's total stockholder return as a percentile of the total stockholder return for the peer group companies over a three-year period as the performance measure for vesting of long-term incentive compensation.

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 during the performance period. The compensation committee selected total stockholder return as the performance measure because long-term executive incentive compensation should align with our long-term performance in stockholder return as compared to other public companies in our industries.

Depending on our total three-year stockholder return compared to the total three-year stockholder returns of our peer group companies, vesting of performance share award opportunities for our named executive officers can range from 0% to 200% of the target award. Vesting of the performance share opportunities will be a function of our rank over the performance period against our peer group companies as delineated in the following table:

The Company's Peer TSR Percentile Rank	Vesting Percentage of Award Target
75th or higher	200%
50th	100%
25th	20%
Less than 25th	0%

Vesting for percentile ranks falling between the intervals is interpolated. If our total stockholder return over the performance period is negative, the shares and dividend equivalents otherwise earned based on the payout percentages above, if any, are reduced in accordance with the following table:

Total Stockholder Return	Reduction in Vesting
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%

Dividend equivalents are paid at the time of settlement in cash based on the number of shares actually vested for the performance period. No dividend equivalents are paid on unvested performance shares.

Actual vesting of performance share awards under the plan over the last five years is shown below:

Performance Period	Vesting Percentage
2015-2017	144%
2014-2016	68%
2013-2015	31%
2012-2014	0%
2011-2013	193%

Results of 2015-2017 Performance Period

Our total stockholder return ranking among the peer group companies prior to our exit from the oil and gas exploration business for the period of January 1, 2015 through November 30, 2015 was 21 out of 24, and the ranking among the peer group companies adjusted for our exit from the oil and gas exploration business for the period of December 1, 2015 through December 31, 2017 was 5 out of 20. This produced a combined percentile ranking of 61% for the 2015-2017 performance period which resulted in a 144% vesting of performance shares and dividend equivalents. The named executive officers received the following long-term compensation for the 2015-2017 performance period:

Name	Target Performance Shares (#)	Performance Shares Vested (#)	Dividend Equivalents (\$)	Value of Shares and Dividend Equivalents at 12/29/17 (\$) ¹
David L. Goodin	72,164	103,916	235,370	3,029,151
Jason L. Vollmer	1,911	2,751	6,231	80,192
David C. Barney	11,745	16,912	38,306	492,985
Jeffrey S. Thiede	12,638	18,198	41,218	530,472
Nicole A. Kivisto	12,234	17,616	39,900	513,506
Doran N. Schwartz ²	14,528	‡	‡	‡

¹ Based on the average of the high and low share price at December 29, 2017, which was \$26.885.

² Mr. Schwartz resigned his position effective September 29, 2017; as a result he forfeited his performance shares.

2017-2019 Performance Period

On February 15, 2017, for the 2017-2019 performance period, the compensation committee determined the target number of performance shares for each named executive officer by multiplying the named executive officer's 2017 base salary by a target long-term incentive percentage and then dividing by the average of the closing prices of our stock from January 1 through January 22, 2017, which was \$28.82 per share. Based on this price, the board of directors, upon recommendation of the compensation committee, awarded the following performance share opportunities to the named executive officers:

Name	Base Salary to Determine Target (\$)	Target Long-Term Incentive % (%)	Long-Term Incentive Target (\$)	Performance Share Opportunities (#)
David L. Goodin	792,750	225	1,783,688	61,890
Jason L. Vollmer	225,500	50	112,750	3,912
David C. Barney	427,140	90	384,426	13,338
Jeffrey S. Thiede	437,750	90	393,975	13,670
Nicole A. Kivisto	378,000	90	340,200	11,804
Doran N. Schwartz ²	391,500	90	352,350	12,225

¹ Based on Mr. Vollmer's position and salary on the date of grant.

² Mr. Schwartz's shares were forfeited upon his resignation effective September 29, 2017.

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The named executive officers must retain 50% of the net after-tax performance shares vested pursuant to the long-term incentive award until the earlier of two years from the date the vested shares are issued or the executive's termination of employment. If the executive's employment is terminated during the performance period for cause at any time, or for any reason other than cause before the executive has reached age 55 and completed ten years of service, all performance shares and related dividend equivalents are forfeited. The compensation committee may also require the executive officer to retain performance shares net of taxes if the executive has not met the stock ownership requirements under the company's stock ownership policy for executives.

Other Benefits

The company provides post employment benefit plans and programs in which our named executive officers may be participants. We believe it is important to provide post-employment benefits which approximate retirement benefits paid by other employers to executives in similar positions. The compensation committee periodically reviews the benefits provided to maintain a market-based benefits package. Our named executive officers participated in the following plans during 2017 which are described below:

Plans	David L. Goodin	Jason L. Vollmer	David C. Barney	Jeffrey S. Thiede	Nicole A. Kivisto	Doran N. Schwartz
401(k)	Yes	Yes	Yes	Yes	Yes	Yes
Pension	Yes	Yes	No	No	Yes	Yes
Supplemental Income Security Plan	Yes	No	Yes	No	Yes	Yes
Nonqualified Defined Contribution Plan	No	Yes	Yes	Yes	No	No

401(k) Retirement Plan

The named executive officers as well as all employees working a minimum of 1,000 hours per year are eligible to participate in the 401(k) plan and defer annual income up to the IRS limit. The company provides a match up to 3% of the employee's elected deferral rate. Contributions and the company match are invested in various funds based on the employee's election including company common stock.

In 2010, the company began offering increased company contributions to our 401(k) plan in lieu of pension plan contributions. For non-bargaining unit employees hired after 2006 or who were not previously participants in the pension plan, the added retirement contribution is 5% of plan eligible compensation. For non-bargaining unit employees hired prior to 2006 and who were participants in the pension plan, the added retirement contributions are based on the employee's age as of December 31, 2009. The retirement contribution is 11.5% for Mr. Goodin, 10.5% for Mr. Schwartz, 9.0% for Ms. Kivisto, 7.0% for Mr. Vollmer, and 5.0% for Messrs. Barney and Thiede. These amounts may be reduced in accordance with the provisions of the 401(k) plan to meet IRS limits.

Pension Plans

Effective in 2006, the defined benefit pension plans were closed to new non-bargaining unit employees and as of December 31, 2009, the defined benefit plans were frozen. For further details regarding the company's pension plans, please refer to the section entitled [Pension Benefits for 2017](#).

Supplemental Income Security Plan

We offer certain key managers and executives benefits under a nonqualified retirement plan, referred to as the Supplemental Income Security Plan (SISP). The SISP provides participants with additional retirement income and death benefits. Effective February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants. For further details regarding the company's SISP, please refer to the section entitled [Pension Benefits for 2017](#). Named executive officers participating in the SISP are Messrs. Goodin, Barney, and Schwartz, and Ms. Kivisto.

The following table reflects our named executive officers' SISP benefits as of December 31, 2017:

Name	SISP Benefits	
	Annual Death Benefit (\$)	Annual Retirement Benefit (\$)
David L. Goodin	552,960	276,480
Jason L. Vollmer	‡	‡
David C. Barney	262,464	131,232
Jeffrey S. Thiede	‡	‡
Nicole A. Kivisto	157,728	78,864
Doran N. Schwartz	262,464	131,232

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan (NQDCP) effective January 1, 2012, to provide retirement and deferred compensation for a select group of management and other highly compensated employees. The compensation committee, upon recommendation from the CEO, determines which employees will participate in the NQDCP and the amount of contributions for any year. After satisfying a vesting requirement for each contribution, distributions will be made in accordance with the terms of the plan. For further details regarding the company's NQDCP, please refer to the section entitled [Nonqualified Deferred Compensation for 2017](#).

For 2017, the compensation committee selected and approved contributions of \$100,000 to Mr. Thiede, \$150,000 to Mr. Barney, and \$22,550 to Mr. Vollmer. The contributions awarded to Messrs. Barney, Thiede, and Vollmer represent 35.18%, 22.84%, and 10% of their base salaries, respectively.

Employment and Severance Agreements

We currently do not have employment or severance agreements with our executives entitling them to specific payments upon termination of employment or a change of control of the company. The compensation committee generally considers providing severance benefits on a case-by-case basis. Any post-employment or change of control benefits available to our executives are addressed within our incentive and retirement plans. Please refer to the section entitled [Potential Payments upon Termination or Change of Control](#).

Compensation Governance

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 limits the deductibility of certain compensation to \$1 million paid to certain officers as a business expense in any tax year. When the compensation committee made its decisions for 2017 compensation, the tax code provided that compensation that qualified as performance-based was excluded from the \$1 million deductibility limit if, among other requirements, the compensation was payable only upon attainment of pre-established, objective performance goals under a plan approved by our stockholders. Legislation signed into law in December 2017 (Tax Reform), however, expanded the number of individuals covered by the Section 162(m) deductibility limit and repealed the exception for performance-based compensation, effective for taxable years beginning after December 31, 2017. Incentive compensation approved by the compensation committee prior to the Tax Reform for our CEO and those executive officers whose overall compensation was likely to exceed \$1 million was generally structured to meet the requirements for deductibility for purposes of Section 162(m). As a result of the Tax Reform, compensation paid to our covered executive officers in excess of \$1 million will not be deductible, unless it qualifies for transition relief applicable to certain arrangements in place as of November 2, 2017.

The compensation committee also considers the accounting and cash flow implications of various forms of executive compensation. We expense salaries and annual incentive compensation as earned. For our equity awards, we record the accounting expense in accordance with Financial Accounting Standards Board 718, which is generally expensed over the vesting period.

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Stock Ownership Requirements

Executives participating in our Long-Term Performance-Based Incentive Plan are required within five years of appointment or promotion into an executive level to own our common stock equal to a multiple of their base salary as outlined in the stock ownership policy. Stock owned through our 401(k) plan or by a spouse is considered in ownership calculations. The level of stock ownership compared to the ownership requirement is determined based on the closing sale price of our stock on the last trading day of the year and base salary at December 31 of the same year. The table shows the named executive officers' holdings as a multiple of their base salary.

Name	Ownership Policy Multiple of Base Salary within 5 Years	Actual Holdings as a Multiple of Base Salary	Ownership requirement must be met by:
David L. Goodin	4X	6.0	1/1/2018
Jason L. Vollmer	3X	0.4	1/1/2023
David C. Barney	3X	1.5	1/1/2019
Jeffrey S. Thiede	3X	1.3	1/1/2019
Nicole A. Kivisto	3X	2.9	1/1/2020
Doran N. Schwartz	n/a	n/a	n/a

¹ Includes stock awards earned net of taxes for the 2015-2017 performance period.

Deferral of Annual Incentive Compensation

We provide executives the opportunity to defer receipt of earned annual incentives. If an executive chooses to defer all or part of an annual incentive, we credit the deferral with interest at a rate determined by the compensation committee. For 2017, the compensation committee chose to use an interest rate of 4.38% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for Aa and Aaa rated companies. The compensation committee's reasons for using this interest rate recognized incentive deferrals are a low-cost source of capital for the company and are unsecured obligations and, therefore, carry a higher risk to the executives.

Clawback

In February 2016, we amended our Long-Term Incentive Plan and Executive Incentive Compensation Plan sections regarding the repayment of incentive compensation due to accounting restatements, commonly referred to as a clawback policy. The compensation committee may, or shall if required, take action to recover incentive-based compensation from specific executives in the event the company is required to restate its financial statements due to material noncompliance with any financial reporting requirements under the securities laws.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits executive officers, which includes our named executive 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 section entitled, [Security Ownership](#) 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, Chair
Karen B. Fagg
William E. McCracken
Patricia L. Moss

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table 2017

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) ³	Total (\$)(j)
David L. Goodin President and CEO	2017	792,750	‡	1,504,546	‡	1,377,007	342,727	40,971	4,058,001
	2016	755,000	‡	1,441,954	‡	1,055,490	218,301	40,246	3,510,991
	2015	755,000	‡	1,386,992	‡	376,745	‡	39,411	2,558,148
Jason L. Vollmér Vice President, CFO and Treasurer	2017	256,625	‡	95,101	‡	230,988	3,681	48,156	634,551
David C. Barney President and CEO of Knife River Corporation	2017	427,140	‡	324,247	‡	483,736	93,786	173,331	1,502,240
	2016	406,800	‡	276,232	‡	593,114	77,565	22,905	1,376,616
	2015	395,000	‡	225,739	‡	637,588	9,530	22,556	1,290,413
Jeffrey S. Thiede President and CEO of MDU Construction Services Group, Inc.	2017	437,750	‡	332,318	‡	743,629	‡	123,163	1,636,860
	2016	425,000	‡	288,598	‡	489,600	‡	122,708	1,325,906
	2015	425,000	‡	242,902	‡	161,857	‡	172,506	1,002,265
Nicole A. Kivistö President and CEO of Montana-Dakota Utilities Co.	2017	378,000	‡	286,955	‡	433,906	96,931	33,049	1,228,841
Doran N. Schwartz Former Vice President and CFO	2017	291,748	‡	297,190	‡	‡	118,256	36,665	743,859
	2016	380,000	6,175	290,292	‡	345,306	77,084	35,772	1,134,629
	2015	380,000	‡	279,228	‡	123,253	‡	35,571	818,052

¹ Amounts in this column represent the aggregate grant date fair value of performance share award opportunities at target 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 the Monte Carlo simulation, as described in Note 10 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2017. For 2017, the total aggregate grant date fair value of performance share award opportunities assuming the highest level of payout would be as follows:

Aggregate grant date fair value at highest payout (\$)

Name	Aggregate grant date fair value at highest payout (\$)
David L. Goodin	3,009,092
Jason L. Vollmer	190,201
David C. Barney	648,494
Jeffrey S. Thiede	664,635
Nicole A. Kivisto	573,910
Doran N. Schwartz ^a	594,380

^a Mr. Schwartz resigned effective September 29, 2017. As a result, he forfeited performance shares reported in column e.

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² Amounts shown for 2017 represent the change in the actuarial present value for the named executive officers' accumulated benefits under the pension plan, SISP, and Excess SISP, collectively referred to as the accumulated pension change, plus above-market earnings on deferred annual incentives as of December 31, 2017.

Name	Accumulated Pension Change	Above Market Interest (\$)
David L. Goodin	330,392	12,335
Jason L. Vollmer	3,681	‡
David C. Barney	93,786	‡
Nicole A. Kivisto	96,629	302
Doran N. Schwartz	118,256	‡

³ All Other Compensation is comprised of:

Name	401(k) (\$) ^a	Life Insurance Premium (\$)	Matching Charitable Contributions (\$)	Nonqualified Defined Contribution Plan (\$)	Total (\$)
David L. Goodin	39,150	621	1,200	‡	40,971
Jason L. Vollmer	24,826	280	500	22,550	48,156
David C. Barney	21,600	531	1,200	150,000	173,331
Jeffrey S. Thiede	21,600	543	1,020	100,000	123,163
Nicole A. Kivisto	32,400	469	180	‡	33,049
Doran N. Schwartz ^b	36,000	365	300	‡	36,665

^a Represents company contributions to the 401(k) plan, which includes matching contributions and retirement contributions made after the pension plans were frozen at December 31, 2009.

^b Mr. Schwartz resigned effective September 29, 2017.

⁴ Mr. Vollmer was promoted to vice president, chief financial officer and treasurer effective September 30, 2017. He appears as a named executive officer for the first time in 2017.

⁵ Ms. Kivisto was promoted to president and chief executive officer of the electric and natural gas distribution segments effective January 9, 2015. She appears as a named executive officer for the first time in 2017.

⁶ Mr. Schwartz resigned effective September 29, 2017. As a result, he forfeited performance shares reported in column e.

Grants of Plan-Based Awards 2017

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			Grant Date Fair Value of Stock and Option Awards (\$) (l)
		Threshold (\$) (c)	Target (\$) (d)	Maximum (\$) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	
David L. Goodin	2/15/2017 ¹	198,188	792,750	1,585,500				
	2/15/2017 ²				12,378	61,890	123,780	1,504,546
Jason L. Vollmer	2/15/2017 ³	33,245	132,981	265,962				
	2/15/2017 ²				782	3,912	7,824	95,101
David C. Barney	2/15/2017 ¹	80,089	320,355	768,852				
	2/15/2017 ²				2,668	13,338	26,676	324,247
Jeffrey S. Thiede	2/15/2017 ¹	82,078	328,313	787,951				
	2/15/2017 ²				2,734	13,670	27,340	332,318
Nicole A. Kivisto	2/15/2017 ³	61,425	245,700	491,400				
	2/15/2017 ²				2,361	11,804	23,608	286,955
Doran N. Schwartz	2/15/2017 ¹	63,619	254,475	508,950				
	2/15/2017 ²				2,445	12,225	24,450	297,190

¹ Annual incentive for 2017 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

² Performance shares for the 2017-2019 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

³ Annual incentive for 2017 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

⁴ Mr. Vollmer's non-equity incentive award shown in columns c, d, and e is prorated based on his promotion effective September 30, 2017.

⁵ Mr. Schwartz resigned effective September 29, 2017, and forfeited his non-equity and equity incentive plan awards.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2017 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 15, 2017. The award opportunities at threshold, target, and maximum are reflected in columns (c), (d), and (e), respectively, of the Grants of Plan-Based Awards Table. The actual amount paid with respect to 2017 performance is reflected in column (g) of the Summary Compensation Table.

As described in the "Annual Incentives" section of the [Compensation Discussion and Analysis](#), payment of annual award opportunities is dependent upon achievement of performance measures; actual payout may range from 0% to 200% of the target except for the construction materials and contracting and construction services segments which may range from 0% to 240%.

Messrs. Goodin, Schwartz, Barney, and Thiede received their 2017 annual incentive award opportunities pursuant to the Long-Term Performance-Based Incentive Plan. To be eligible to receive a payment, they must remain employed by the company through December 31, 2017. Mr. Schwartz resigned his position effective September 29, 2017, and therefore was not eligible to receive an annual incentive award.

The performance measures associated with the annual incentive may not be adjusted if the adjustment would increase their annual incentive award payment, unless the compensation committee determined and established the adjustment in writing within 90 days of the beginning of the performance period. The compensation committee may at its sole discretion use negative discretion based on subjective or objective measures and adjust any annual incentive award payment downward.

Mr. Vollmer and Ms. Kivisto were awarded their annual incentive opportunities pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan. Under the Executive Incentive Compensation Plan, executives who retire during the year at age 65 remain

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eligible to receive an award, but executives who terminate employment for other reasons are not eligible for an award. The compensation committee generally does not modify the performance measures; 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 measures, the compensation committee, in consultation with the CEO, may modify the performance measures. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether to adjust payment of awards downward based upon individual performance. For further discussion of the specific 2017 incentive plan performance measures and results, see the ,Annual Incentivesf section in the ,[Compensation Discussion and Analysis](#)f

Long-Term Incentive

The compensation committee recommended long-term incentive award opportunities for the named executive officers in the form of performance shares, and the board approved the award opportunities at its meeting on February 15, 2017. The long-term incentive opportunities are presented as the number of performance shares at threshold, target, and maximum in columns (f), (g), and (h) of the Grants of Plan-Based Awards Table. The value of the long-term performance-based incentive opportunities is based on the aggregate grant date fair value and is reflected in column (e) of the Summary Compensation Table and column (l) of the Grant of Plan-Based Awards Table.

Depending on our 2017-2019 total stockholder return compared to the total three-year stockholder returns of our peer group companies, executives will receive from 0% to 200% of the target awards in February 2020. We also will pay dividend equivalents in cash on the number of shares actually vested for the performance period. The dividend equivalents will be paid in 2020 at the same time as the performance share awards are issued. In the event the company's 2017-2019 total stockholder return is negative, the number of shares that would otherwise vest for the performance period will be reduced from 50% to 100%. For further discussion of the specific long-term incentive plan, see the ,Long-Term Incentivesf section in the ,[Compensation Discussion and Analysis](#)f

Nonqualified Defined Contribution Plan

The CEO recommends participants and contribution amounts to the Nonqualified Defined Contribution Plan which are approved by the compensation committee of the board of directors. The purpose of the plan is to recognize outstanding performance coupled with enhanced retention as the Nonqualified Defined Contribution Plan requires a vesting period. The amount shown in column (i) - All Other Compensation of the Summary Compensation Table includes contributions of \$100,000 for Mr. Thiede, \$150,000 for Mr. Barney, and \$22,550 for Mr. Vollmer. For further information, see the section entitled ,[Nonqualified Deferred Compensation for 2017](#) .f

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	792,750	‡	4,058,001	19.5 %
Jason L. Vollmer	256,625	‡	634,551	40.4 %
David C. Barney	427,140	‡	1,502,240	28.4 %
Jeffrey S. Thiede	437,750	‡	1,636,860	26.7 %
Nicole A. Kivisto	378,000	‡	1,228,841	30.8 %
Doran N. Schwartz	291,748	‡	743,859	39.2 %

Outstanding Equity Awards at Fiscal Year-End 2017

Name (a)	Stock Awards				Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (\$) (j) ²
	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) ¹		
David L. Goodin	‡	‡	354,234	9,521,810	
Jason L. Vollmer	‡	‡	14,138	380,029	
David C. Barney	‡	‡	63,998	1,720,266	
Jeffrey S. Thiede	‡	‡	67,544	1,815,583	
Nicole A. Kivisto	‡	‡	60,317	1,621,321	
Doran N. Schwartz	‡	‡	71,267	1,915,657	

¹ Below is a breakdown by year of the outstanding performance share plan awards:

Performance Period End	2015 Award	2016 Award	2017 Award	Total
	12/31/2017	12/31/2018	12/31/2019	
David L. Goodin	144,328	197,528	12,378	354,234
Jason L. Vollmer	3,822	9,534	782	14,138
David C. Barney	23,490	37,840	2,668	63,998
Jeffrey S. Thiede	25,276	39,534	2,734	67,544
Nicole A. Kivisto	24,468	33,488	2,361	60,317
Doran N. Schwartz	29,056	39,766	2,445	71,267

Shares for the 2015 award are shown at the maximum level (200%) based on results for the 2015-2017 performance cycle above target.

Shares for the 2016 award are shown at the maximum level (200%) based on results for the first two years of the 2016-2018 performance cycle above target.

Shares for the 2017 award are shown at the threshold (20%) based on results for the first year of the 2017-2019 performance cycle below threshold.

² Value based on the number of performance shares reflected in column (i) multiplied by \$26.88, the year-end per share closing stock price for 2017.

³ Mr. Schwartz resigned his position effective September 29, 2017. As a result, he forfeited all shares associated with the 2015-2017, 2016-2018, and 2017-2019 performance periods.

While for purposes of the Outstanding Equity Awards at Fiscal Year-End 2017 Table, the number of shares and value shown for the 2015-2017 performance cycle is at 200% of target, the actual results for the performance period certified by the compensation committee and settled on February 16, 2018, was 144% of target. For further information, see the „Long-Term Incentives” section of the [Compensation Discussion and Analysis](#)

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Option Exercises and Stock Vested During 2017

Name (a)	Stock Awards	
	Number of Shares Acquired on Vesting (#) (d) ¹	Value Realized on Vesting (\$) (e) ²
David L. Goodin	22,900	654,368
Jason L. Vollmer	‡	‡
David C. Barney	5,081	145,190
Jeffrey S. Thiede	5,349	152,848
Nicole A. Kivisto	2,755	78,724
Doran N. Schwartz	6,017	171,936

¹ Reflects performance shares for the 2014-2016 performance period ended December 31, 2016, which were approved February 16, 2017.

² Reflects the value of vested performance shares based on the closing stock price of \$26.37 per share on February 16, 2017, and the dividend equivalents paid on the vested shares.

Pension Benefits for 2017

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c) ¹	Present Value of Accumulated Benefit (\$) (d)	Payments During Last Fiscal Year (\$) (e)
David L. Goodin	Pension	26	1,220,459	‡
	Basic SISP ²	10	2,500,218	‡
	Excess SISP ³	26	39,023	‡
Jason L. Vollmer	Pension	4	24,451	‡
	Basic SISP ²	n/a	‡	‡
	Excess SISP ³	n/a	‡	‡
David C. Barney	Pension ³	n/a	‡	‡
	Basic SISP ²	10	1,477,483	‡
	Excess SISP ³	n/a	‡	‡
Jeffrey S. Thiede	Pension ³	n/a	‡	‡
	Basic SISP ³	n/a	‡	‡
	Excess SISP ³	n/a	‡	‡
Nicole A. Kivisto	Pension	14	254,722	‡
	Basic SISP ²	6	489,832	‡
	Excess SISP ³	n/a	‡	‡
Doran N. Schwartz	Pension	4	125,585	‡
	Basic SISP ²	10	923,825	‡
	Excess SISP ³	n/a	‡	‡

¹ Years of credited service related to the pension plan reflects the years of participation in the plan as of December 31, 2009, when the pension plan was frozen. Years of credited service related to the Basic SISP reflects the years toward full vesting of the benefit which is 10 years. Years of credited service related to Excess SISP reflects the same number of credited years of services as the pension plan.

² The present value of accumulated benefits for the Basic SISP assumes the named executive officer would be fully vested in the benefit on the benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

³ Messrs. Barney and Thiede are not eligible to participate in the pension plans. Mr. Thiede does not participate in the SISP. Mr. Goodin is the only named executive officer eligible to participate in the Excess SISP.

The amounts shown for the pension plan, Basic SISP, and Excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2017, calculated using:

- ... a 3.18% discount rate for the Basic SISP and Excess SISP;
- ... a 3.36% discount rate for the pension plan;
- ... the Society of Actuaries RP-2014 Adjusted to 2006 Total Dataset Mortality with Scale MP-2017 for post-retirement mortality; and
- ... no recognition of future salary increases or pre-retirement mortality.

The actuary assumed a retirement age of 60 for the pension, Basic SISP, and Excess SISP benefits and assumed retirement benefits commence at age 60 for the pension and 65 for Basic and Excess SISP benefits.

Pension Plan

The MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees (pension plan) applies to employees hired before 2006 and was amended to cease benefit accruals as of December 31, 2009. The benefits under the pension plan are based on a participant's average annual salary over the 60 consecutive month period where the participant received the highest annual salary between 1999 and 2009. Benefits are paid as straight life annuities for single participants and as actuarially reduced annuities with a survivor benefit for married participants unless they choose otherwise.

Supplemental Income Security Plan

The Supplemental Income Security Plan (SISP), a defined benefit nonqualified retirement plan, is offered to select key managers and executives. SISP benefits are determined by reference to levels defined within the plan. Our compensation committee, after receiving recommendations from our CEO, determined each participant's level within the plan. On February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants.

Basic SISP Benefits

Basic SISP is a supplemental retirement benefit intended to augment the retirement income provided under the pension plans. The Basic SISP benefits are subject to the following ten-year vesting schedule:

- ... 0% vesting for less than three years of participation;
- ... 20% vesting for three years of participation;
- ... 40% vesting for four years of participation; and
- ... an additional 10% vesting for each additional year of participation up to 100% vesting for ten years of participation.

Participants can elect to receive the Basic SISP as:

- ... monthly retirement benefits only;
- ... monthly death benefits paid to a beneficiary only; or
- ... a combination of retirement and death benefits, where each benefit is reduced proportionately.

Regardless of the election, if the participant dies before the SISP retirement benefit commences, only the SISP death benefit is provided.

Basic SISP benefits vested as of December 31, 2004, are grandfathered under Section 409A of the Internal Revenue Code (Section 409A) and are subject to the SISP provisions then in effect. Typically, the grandfathered Section 409A SISP benefits are paid over 15 years, with benefits commencing when the participant attains age 65 or when the participant retires if they work beyond age 65. Basic SISP benefits vesting after December 31, 2004, are governed by amended provisions in the plan intended to comply with Section 409A. The SISP benefits for key employees as defined by Section 409A commence six months after the participant attains age 65 or when the participant retires if they work beyond age 65. The benefits are paid over a 173-month period where the first payment includes the equivalent of six months of payments plus interest equal to one-half of the annual prime interest rate on the participant's last date of employment.

The following are Messrs. Goodin and Barney's benefits under the grandfathered provision and those subject to Section 409A.

	Grandfathered (\$)	Subject to „409A (\$)	Total (\$)
David L. Goodin	271,291	2,228,927	2,500,218
David C. Barney	362,075	1,115,408	1,477,483

Proxy Statement

Excess SISP Benefits

Excess SISP is an additional retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans. Excess SISP benefits are equal to the difference between 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 the actual benefits payable to the participant under the pension plans. Participants are only eligible for the Excess SISP benefits if the participant is fully vested under the pension plan, their employment terminates prior to age 65, and benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation.

In 2009, the SISP was amended to limit eligibility for the Excess SISP benefit. Mr. Goodin is the only named executive officer eligible for the Excess SISP benefit and must remain employed with the company until age 60 in order to receive the 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.

Both Basic and Excess SISP benefits are forfeited if the participant's employment is terminated for cause.

Nonqualified Deferred Compensation 2017

Deferred Annual Incentive Compensation

Executives participating in the annual 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 2017 was 4.38% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for ,A_f and ,Baa_f rated companies. 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 earned. The amounts are paid in accordance with the participant's election in either a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts deferred would immediately become payable. For purposes of deferred annual incentive compensation, a change of control 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 gross fair market value of all of our assets.

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 employees. The compensation committee approves the amount of employer contributions under the Nonqualified Defined Contribution Plan and the obligations under the plan constitute an unsecured promise of the company to make such payments. The company credits contributions to plan accounts which capture the hypothetical investment experience based on the participant's elections. Contributions made prior to 2017 vest four years after each contribution in accordance with the terms of the plan. Contributions made in 2017 vest rateably over a three-year period with 1/3 vesting after the first year, an additional 1/3 after the second year, and the final 1/3 after the third year. Amounts shown as aggregate earnings in the table below for Messrs. Vollmer, Barney, and Thiede reflect the change in investment value at market rates. Participants may elect to receive their vested contributions and investment earnings either in a lump sum upon separation from service with the company or in annual installments over a period of years 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.

The table below includes individual contributions from deferrals of annual incentive compensation and company contributions under the Nonqualified Defined Contribution Plan:

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	527,745	‡	28,630	‡	752,052 ¹
Jason L. Vollmer	‡	22,550	5,125	‡	27,675 ²
David C. Barney	‡	150,000	23,341	‡	173,341 ³
Jeffrey S. Thiede	‡	100,000	83,052	‡	579,981 ⁴
Nicole A. Kivisto	‡	‡	723	‡	16,945
Doran N. Schwartz	‡	‡	‡	‡	‡

¹ Mr. Goodin deferred 50% of his 2016 annual incentive compensation which was \$1,055,490 as reported in the Summary Compensation Table for 2016.

² Mr. Vollmer received \$22,550 under the Nonqualified Defined Contribution Plan for 2017. This is reported in column (i) of the Summary Compensation Table for 2017.

³ Mr. Barney received \$150,000 under the Nonqualified Defined Contribution Plan for 2017. This is reported in column (i) of the Summary Compensation Table for 2017.

⁴ Mr. Thiede received \$100,000 under the Nonqualified Defined Contribution Plan for 2017. Mr. Thiede's balance also includes contributions of \$100,000 for 2016, \$150,000 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 the Proxy Statement for its respective year, where applicable.

Potential Payments upon Termination or Change of Control

The Potential Payments upon Termination or Change of Control Table shows the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios or upon a change of control. For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2017. Mr. Schwartz received no actual termination payments upon his resignation effective September 29, 2017.

The table excludes compensation and benefits that our named executive officers would have already earned during their employment with us whether or not a termination or change of control event had occurred or 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 also do not include Nonqualified Defined Contribution Plan or deferred annual compensation amounts which are shown and explained in the Nonqualified Deferred Compensation for 2017 Table.

Compensation

Upon a change of control, annual incentives granted under our Long-Term Performance-Based Incentive Plan (LTIP) would vest at target and be paid in cash. Messrs. Goodin, Barney, and Thiede were awarded their annual incentives for 2017 under the LTIP and would receive the value of their annual incentive compensation at the target amount under the change of control scenarios. Having been employed for the entire year, no amounts are shown for annual incentives in the tables for Messrs. Goodin, Barney, and Thiede under termination scenarios, as they would be eligible to receive their annual incentive award based on the level that performance measures were achieved for the performance period regardless of a termination scenario occurring on December 31, 2017.

Mr. Vollmer and Ms. Kivisto were granted their annual incentive award under the Executive Incentive Compensation Plan (EICP) which has no change of control provision in regards to annual incentive compensation other than for deferred compensation. Unless otherwise determined by the compensation committee for named executive officers, or employment termination after age 65, the EICP requires participants to remain employed with the company through the service year to be eligible for a payout. Having been employed for the entire performance period, no amounts are shown for annual incentives in the tables for Mr. Vollmer or Ms. Kivisto, as they would be eligible to receive their annual incentive award based on the level that performance measures were achieved for the performance period regardless of termination or change of control scenarios occurring on December 31, 2017.

Proxy Statement

Upon a change of control, performance share awards under the LTIP would be deemed fully earned and vest at their target levels for the named executive officers. For this purpose, the term "change of control" is defined in the LTIP as:

- ... the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock;
- ... a majority of our board of directors whose election or nomination was not approved by a majority of the incumbent 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.

For termination scenarios other than a change of control, our award agreements provide that performance share awards are forfeited if the participant's employment terminates before the participant has reached age 55 and completed 10 years of service. If a participant's employment is terminated other than for cause after reaching age 55 and completing 10 years of service, performance shares are prorated as follows:

- ... termination of employment during the first year of the performance period = shares are forfeited;
- ... termination of employment during the second year of the performance period = performance shares earned are prorated based on the number of months employed during the performance period; and
- ... termination of employment during the third year of the performance period = full amount of any performance shares earned are received.

Under the termination scenarios, Messrs. Goodin, Barney, and Thiede would receive performance shares as they have each reached age 55 and have 10 or more years of service. The number of performance shares received would be based on the following:

- ... 2015-2017 performance shares would vest based on the achievement of the performance measure for the period ended December 31, 2017, which was 144%;
- ... 2016-2018 performance shares would be prorated at 24 out of 36 months (2/3) of the performance period and vest based on the achievement of the performance measure for the period ended December 31, 2018. For purposes of the Potential Payments upon Termination or Change of Control Table, the vesting is shown at 100%; and
- ... 2017-2019 performance shares would be forfeited.

For purposes of calculating the performance share value shown in the Potential Payments upon Termination or Change of Control Table, the number of vesting shares was multiplied by the average of the high and low stock price for the last market day of the year, which was December 29, 2017. Dividend equivalents based on the number of vesting shares are also included in the amounts presented.

Neither Ms. Kivisto nor Mr. Vollmer have reached age 55; therefore, they are not eligible for vesting of performance shares in the event of their termination.

Benefits and Perquisites

Supplemental Income Security Plan

Basic SISP benefits presented in the Potential Payments upon Termination or Change of Control Table represent the present value of vested Basic SISP as of December 31, 2017 for payments commencing at age 65 and payable for 15 years. Only Messrs. Goodin, Barney, and Ms. Kivisto are eligible for Basic SISP benefits. While Messrs. Goodin and Barney are 100% vested in their SISP benefit, Ms. Kivisto entered the plan in 2011 and is only 70% vested in her SISP benefit at December 31, 2017. In the event of death, Messrs. Goodin, Barney, and Ms. Kivisto's beneficiaries would receive monthly death benefit payments for 15 years. The present value calculations used a 3.18% discount rate and the following monthly SISP benefit payments:

	Monthly SISP Retirement Payment (\$)	Monthly SISP Death Payment (\$)
David L. Goodin	23,040	46,080
David C. Barney	10,936	21,872
Nicole A. Kivisto	3,500	13,144

The present value of the SISP benefit under the disability scenario for Ms. Kivisto reflects credit for two additional years of vesting or 90% as provided for in the plan. The terms of the Basic SISP benefit are described following the Pension Benefits for 2017 Table.

Disability

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a salary limit of \$200,000 for officers and \$100,000 for other salaried employees when calculating benefits. For all eligible employees, disability payments continue until age 65 if disability occurs at or before age 60 and for five years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The disability amounts in the Potential Payments upon Termination or Change of Control Table 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. For Messrs. Goodin and Vollmer and Ms. Kivisto, who participate in the pension plan, the amount represents the present value of the disability benefit after reduction for retirement benefits using a discount rate of 3.36%. Because Mr. Goodin's retirement benefit is greater than the disability benefit, the amount shown is zero. For Messrs. Barney and Thiede, who do not participate in the pension plan, the amount represents the present value of the disability benefit without reduction for retirement benefits using the discount rate of 3.18%, which is considered a reasonable rate for purposes of the calculation.

Severance

None of the current named executive officers have employment or severance agreements with the company. The compensation committee generally considers providing severance benefits on a case-by-case basis. Because severance payments are discretionary, no amounts are presented in the tables.

Proxy Statement

Potential Payments upon Termination or Change of Control Table

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) (\$)
David L. Goodin						
Compensation:						
Annual Incentive	‡	‡	‡	‡	792,750	792,750
Performance Shares	4,900,080	4,900,080	4,900,080	4,900,080	6,621,837	6,621,837
Benefits and Perquisites:						
Basic SISP	2,502,092	2,502,092	‡	2,502,092	2,502,092	‡
SISP Death Benefits	‡	‡	6,607,177	‡	‡	‡
Disability Benefits	‡	‡	‡	‡	‡	‡
Total	7,402,172	7,402,172	11,507,257	7,402,172	9,916,679	7,414,587
Jason L. Vollmer						
Compensation:						
Performance Shares	‡	‡	‡	‡	299,366	299,366
Benefits and Perquisites:						
Disability Benefits	‡	‡	‡	980,108	‡	‡
Total	980,108	299,366	299,366
David C. Barney						
Compensation:						
Annual Incentive	‡	‡	‡	‡	320,355	320,355
Performance Shares	851,383	851,383	851,383	851,383	1,248,908	1,248,908
Benefits and Perquisites:						
Basic SISP	1,463,790	1,463,790	‡	1,463,790	1,463,790	‡
SISP Death Benefits	‡	‡	3,136,115	‡	‡	‡
Disability Benefits	‡	‡	‡	277,761	‡	‡
Total	2,315,173	2,315,173	3,987,498	2,592,934	3,033,053	1,569,263
Jeffrey S. Thiede						
Compensation:						
Annual Incentive	‡	‡	‡	‡	328,313	328,313
Performance Shares	904,925	904,925	904,925	904,925	1,308,189	1,308,189
Benefits and Perquisites:						
Disability Benefits	‡	‡	‡	470,306	‡	‡
Total	904,925	904,925	904,925	1,375,231	1,636,502	1,636,502
Nicole A. Kivisto						
Compensation:						
Performance Shares	‡	‡	‡	‡	1,158,901	1,158,901
Benefits and Perquisites:						
Basic SISP	261,024	261,024	‡	335,704	261,024	‡
SISP Death Benefits	‡	‡	1,884,651	‡	‡	‡
Disability Benefits	‡	‡	‡	784,536	‡	‡
Total	261,024	261,024	1,884,651	1,120,240	1,419,925	1,158,901

CEO Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K, we are providing information regarding the relationship of the annual total compensation of David L. Goodin, our president and chief executive officer, to the annual total compensation of our median employee.

Our employee workforce fluctuates during the year largely depending on the seasonality, number, and size of construction activity conducted by our businesses. Approximately 49.8% of our employee workforce is employed under union bargained labor contracts which define compensation and benefits for participants which may include payments made by the company associated with employee participation in union benefit and pension plans.

We identified the median employee by examining the 2017 taxable wage information for all individuals on the company's payroll records as of December 31, 2017, excluding Mr. Goodin. All of the company's employees are located in the United States. We made no adjustments to annualize compensation for individuals employed for only part of the year. We selected taxable wages as reported to the Internal Revenue Service on Form W-2 for 2017 to identify the median employee as it includes substantially all of the compensation for our median employee and provided a reasonably efficient and economic manner for the identification of the median employee. Our median employee works for our gas distribution segment. He is a unionized employee with compensation consisting of wages, meal allowances, company matching 401(k) contributions and a years of service award. Our median employee does not participate in the company's pension plan since he joined the company in 2011, after the plan was frozen. He does receive an additional 5% company match to his 401(k) plan in lieu of pension contributions.

Once identified, we categorized the median employee's compensation to correspond to the compensation components as reported in the Summary Compensation Table. For 2017, the total annual compensation of Mr. Goodin as reported in the Summary Compensation Table included in this Proxy Statement was \$4,058,001, and the total annual compensation of our median employee was \$84,883. Based on this information, the 2017 ratio of annual total compensation of Mr. Goodin to the median employee was 48 to 1.

AUDIT MATTERS

ITEM 3: RATIFICATION OF THE APPOINTMENT OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2018

The audit committee at its February 2018 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2018. 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 2018, 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 annual 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 the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2018.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2018 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the annual meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal.

Annual Evaluation and Selection of Deloitte & Touche LLP

The audit committee annually evaluates the performance of its independent registered public accounting firm, including the senior audit engagement team, and determines whether to re-engage the current independent accounting firm or consider other firms. Factors considered by the audit committee in deciding whether to retain the current independent accounting firm include:

- ... Deloitte & Touche LLP's capabilities considering the complexity of our business and the resulting demands placed on Deloitte & Touche LLP in terms of technical expertise and knowledge of our industry and business;
- ... the quality and candor of Deloitte & Touche LLP's communications with the audit committee and management;
- ... Deloitte & Touche LLP's independence;
- ... the quality and efficiency of the services provided by Deloitte & Touche LLP, including input from management on Deloitte & Touche LLP's performance and how effectively Deloitte & Touche LLP demonstrated its independent judgment, objectivity, and professional skepticism;
- ... external data on audit quality and performance, including recent Public Company Accounting Oversight Board reports on Deloitte & Touche LLP and its peer firms; and
- ... the appropriateness of Deloitte & Touche LLP's fees, tenure as our independent auditor, including the benefits of a longer tenure, and the controls and processes in place that help ensure Deloitte & Touche LLP's continued independence.

Based on this evaluation, the audit committee and the board believe that retaining Deloitte & Touche LLP to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2018, is in the best interests of our company and its stockholders.

The audit committee also oversees the process for, and ultimately approves, the selection of our independent registered public accounting firm's lead engagement partner at the five-year mandatory rotation period. Prior to the mandatory rotation period in 2017, at the audit committee's instruction, Deloitte & Touche LLP selected candidates to be considered for the lead engagement partner role, who were then interviewed by members of our company's senior management. After considering the candidates recommended by Deloitte & Touche LLP, senior management made a recommendation to the audit committee regarding the new engagement partner. After discussing the qualifications of the proposed lead engagement partner with the current lead engagement partner, the audit committee chair interviewed the leading candidate, and the audit committee then considered the appointment and voted as an audit committee on the selection. The change in lead engagement partner after the current five-year rotation period occurred in February 2017.

Audit Fees and Non-Audit 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 2017 and 2016:

	2017	2016
Audit Fees ¹	\$ 2,327,450	\$ 2,526,900
Audit-Related Fees ²	46,790	16,710
Tax Fees ³	17,483	‡
All Other Fees ⁴	‡	3,087
Total Fees ⁵	\$ 2,391,723	\$ 2,546,697
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0.7 %	0.1 %

¹ Audit fees for 2017 and 2016 consisted of fees for services rendered for the audit of our annual financial statements and subsidiaries, statutory and regulatory audits, reviews of quarterly financial statements, a Form S-3 Registration Statement (2017) filing, and a Form S-8 Registration Statement (2016) filing, and audits for discontinued operations for Dakota Prairie Refining, LLC (2016).

² Audit-related fees for 2017 and 2016 are associated with Intermountain Gas Company Investment Tax Credit procedures (2017), supplemental schedule review for Knife River Corporation's Northwest Region (2017), and Intermountain Gas Company public utility review (2016).

³ Tax fees for 2017 consisted of fees for tax training for regulated operations.

⁴ All other fees for 2016 are associated with a pollution control project at Big Stone electric generating facility.

⁵ Total fees reported above include out-of-pocket expenses related to the services provided of \$282,483 for 2017 and \$350,000 for 2016.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Registered Public Accounting Firm

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2017 in accordance with the pre-approval policy and procedures the audit committee adopted in 2003. 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 SEC.

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 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.

AUDIT COMMITTEE REPORT

In connection with our financial statements for the year ended December 31, 2017, 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. 1301, 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 above, 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, 2017, for filing with the SEC.

Dennis W. Johnson, Chair

Mark A. Hellerstein

A. Bart Holaday

John K. Wilson


INFORMATION ABOUT THE ANNUAL MEETING


Who can Vote? Stockholders of record at the close of business on March 9, 2018, are entitled to vote each share they owned on that date on each matter presented at the meeting and any adjournment(s) thereof. As of March 9, 2018, we had 195,304,376 shares of common stock outstanding entitled to one vote per share.

Distribution of our Proxy Materials using Notice and Access We distributed proxy materials to certain of our stockholders via the Internet under the SEC's Notice and Access rules to reduce our costs and decrease the environmental impact of our proxy materials. Using this method of distribution, on or about March 23, 2018, we mailed a Notice Regarding the Availability of Proxy Materials (Notice) that contains basic information about our 2018 annual meeting and instructions on how to view all proxy materials, and vote electronically, on the Internet. If you received the Notice and prefer to receive a paper copy of the proxy materials, follow the instructions in the Notice for making this request and the materials will be sent promptly to you via the preferred method. Stockholders who do not receive the Notice will receive a paper copy of our proxy materials, which will be sent on or about March 29, 2018.


How to Vote You are encouraged to vote in advance of the meeting using one of the following voting methods, even if you are planning to attend the 2018 Annual Meeting of Stockholders.


Registered Stockholders Stockholders of record who hold their shares directly with our stock registrar can vote any one of four ways:

 Via the Internet: Go to the website shown on the Notice or Proxy Card, if you received one, and follow the instructions.

 By Telephone: Call the telephone number shown on the Notice or Proxy Card, if you received one, and follow the instructions given by the voice prompts.

Voting via the Internet or by telephone authorizes the named proxies to vote your shares in the same manner as if you marked, signed, dated, and returned a Proxy Card by mail. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 7, 2018.

 By Mail: If you received paper copies of the Proxy Statement, Annual Report, and Proxy Card, mark, sign, date, and return the Proxy Card in the postage-paid envelope provided.

 In Person: Attend the annual meeting, or send a personal representative with an appropriate proxy, to vote by ballot at the meeting. (See [Notice of Annual Meeting](#) and [Annual Meeting Admission](#))

Beneficial Stockholders Stockholders whose shares are held beneficially in the name of a bank, broker, or other holder of record (sometimes referred to as holding shares "in street name"), will receive voting instructions from said bank, broker, or other holder of record. If you wish to vote in person at the meeting, you must obtain a legal proxy from your bank, broker or other holder of record of your shares and present it at the meeting.

See discussion below in the MDU Resources Group, Inc. 401(k) Plan for voting instructions for shares held under our 401(k) plan.

Revoking Your Proxy or Changing Your Vote You may change your vote at any time before the proxy is exercised.

Registered Stockholders:

f If you voted by mail: you may revoke your proxy by executing and delivering a timely and valid later dated proxy, by voting by ballot at the meeting, or by giving written notice of revocation to the corporate secretary.

f If you voted via the Internet or by telephone: you may change your vote with a timely and valid later Internet or telephone vote, as the case may be, or by voting by ballot at the meeting.

f Attendance at the meeting will not have the effect of revoking a proxy unless (1) you give proper written notice of revocation to the corporate secretary before the proxy is exercised, or (2) you vote by ballot at the meeting.

Beneficial Stockholders Follow the specific directions provided by your bank, broker, or other holder of record to change or revoke any voting instructions you have already provided. Alternatively, you may vote your shares by ballot at the meeting if you obtain a legal proxy from your bank, broker, or other holder of record and present it at the meeting.

Proxy Statement

Discretionary Voting Authority If you complete and submit your proxy voting instructions, the individuals named as proxies will follow your instructions. If you are a stockholder of record and you submit proxy voting instructions but do not direct how to vote on each item, the individuals named as proxies will vote as the board recommends on each proposal. The individuals named as proxies will vote on any other matters properly presented at the annual meeting in accordance with their discretion. Our bylaws set forth requirements for advance notice of any nominations or agenda items to be brought up for voting at the annual meeting, and we have not received timely notice of any such matters, other than the items from the board of directors described in this Proxy Statement.

Voting Standards A majority of outstanding shares of stock entitled to vote must be present in person or represented by proxy to hold the meeting.

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.

Approval of each of the other matters on the agenda requires the affirmative vote of a majority of the shares of common stock present or represented by proxy during the meeting. For each of these proposals, abstentions have the same effect as against votes. If you are a beneficial holder and do not provide specific voting instruction to your broker, the organization that holds your shares will not be authorized to vote your shares, which would result in broker non-votes on proposals other than the ratification of the selection of our independent registered public accounting firm for 2018. Abstentions and broker non-votes are counted for purposes of determining whether a quorum is present at the annual meeting.

The following chart describes the proposals to be considered at the annual meeting, the vote required to elect directors and to adopt each other proposal, and the manner in which votes will be counted:

Item No.	Proposal	Voting Options	Vote Required to Adopt the Proposal	Effect of Abstentions	Effect of Broker Non-Votes
1	Election of Directors	For, against, or abstain on each nominee	A nominee for director will be elected if the votes cast for such nominee exceed the votes cast against such nominee.	No effect	No effect
2	Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	No effect
3	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2018	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	Brokers have discretion to vote

Proxy Solicitation The board of directors is furnishing proxy materials to solicit proxies for use at the Annual Meeting of Stockholders on May 8, 2018, and any adjournment(s) thereof. Proxies are solicited 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 proxies and will reimburse brokers and others for forwarding proxy materials to stockholders.

Electronic Delivery of Proxy Statement and Annual Report Documents

For stockholders receiving proxy materials by mail, you can elect to receive an email in the future that will provide electronic links to these documents. Opting to receive your proxy materials online will save the company the cost of producing and mailing documents to your home or business and will also give you an electronic link to the proxy voting site.

- f* Registered Stockholders If you vote on the Internet, simply follow the prompts for enrolling in the electronic proxy delivery service. You may also enroll in the electronic proxy delivery service at any time in the future by going directly to <http://enroll.icsdelivery.com/mdu> to request electronic delivery. You may revoke an electronic delivery election at this site at any time.
- f* Beneficial Stockholders If you hold your shares in a brokerage account, you may also have the opportunity to receive copies of the proxy materials electronically. You may enroll in the electronic proxy delivery service at any time by going directly to <http://enroll.icsdelivery.com/mdu> to request electronic delivery. You may also revoke an electronic delivery election at this site at any time. In addition, you may also check the information provided in the proxy materials mailed to you by your bank or broker regarding the availability of this service or contact your bank or broker to request electronic delivery.

Householding of Proxy Materials

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 will promptly deliver, 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.

MDU Resources Group, Inc. 401(k) Plan

This Proxy Statement is being used to solicit voting instructions from participants in the MDU Resources Group, Inc. 401(k) Plan with respect to shares of our common stock that are held by the trustee of the plan for the benefit of plan participants. If you are a plan participant and also own other shares as a registered stockholder or beneficial owner, you will separately receive a Notice or proxy materials to vote those other shares you hold outside of the MDU Resources Group, Inc. 401(k) Plan. If you are a plan participant, you must instruct the plan trustee to vote your shares by utilizing one of the methods described on the voting instruction form that you receive in connection with shares held in the plan. If you do not give voting instructions, the trustee generally will vote the shares allocated to your personal account in accordance with the recommendations of the board of directors. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 3, 2018.

Annual Meeting Admission and Guidelines

Admission: All stockholders as of the record date of March 9, 2018, are cordially invited and urged to attend the annual meeting. You must request an admission ticket in order to attend. If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.

If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 9, 2018, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.

Requests for admission tickets must be received no later than May 1, 2018. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.

Guidelines: The business of the meeting will follow as set forth in the agenda which you will receive at the meeting entrance. The use of cameras or sound recording equipment is prohibited, except by those employed by the company to provide a record of the proceedings. The use of cell phones and other personal communication devices is also prohibited during the meeting. All devices must be turned off or muted. No firearms or weapons, banners, packages, or signs will be allowed in the meeting room. MDU Resources Group, Inc. reserves the right to inspect all items, including handbags and briefcases, that enter the meeting room.

Proxy Statement

Conduct of the Meeting

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 proxy to vote or act on such matters in their discretion.

Stockholder Proposals, Director Nominations, and Other Items of Business for 2019 Annual Meeting

Stockholder Proposals for Inclusion in Next Year's Proxy Statement can be included in the proxy materials for our 2019 annual meeting, a stockholder proposal must be received by the corporate secretary no later than November 23, 2018, unless the date of the 2019 annual meeting is more than 30 days before or after May 8, 2019, in which case the proposal must be received a reasonable time before we begin to print and mail our proxy materials. The proposal must also comply with all applicable requirements of Rule 14a-18 under the Securities and Exchange Act of 1934.

Director Nominations and Other Stockholder Proposals Raised From the Floor at the 2019 Annual Meeting of Stockholders. Under our bylaws, if a stockholder intends to nominate a person as a director, or present other items of business at an annual meeting, the stockholder must provide written notice of the director nomination or stockholder proposal at least 90 days prior to the anniversary of the most recent annual meeting. Notice of director nominations or stockholder proposals for our 2019 annual meeting must be received by February 7, 2019, and meet all the requirements and contain all the information, including the completed questionnaire for director nominations, provided by our bylaws. The requirements for such notice can be found in our bylaws, a copy of which is 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, 2017, which is required to be filed with the SEC. 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, North Dakota 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 23, 2018

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 2017 was 855,319 shares.

Common Stock Prices

	High	Low	Close
2017			
First Quarter	\$29.74	\$25.83	\$27.37
Second Quarter	27.89	25.58	26.20
Third Quarter	27.73	25.14	25.95
Fourth Quarter	28.22	25.89	26.88
2016			
First Quarter	\$19.55	\$15.57	\$19.46
Second Quarter	24.01	18.70	24.00
Third Quarter	25.79	22.47	25.44
Fourth Quarter	29.92	24.49	28.77

Shareowner Service Plus Plan

The Shareowner Service Plus Plan provides interested investors the opportunity to purchase shares of MDU Resources' common stock and to reinvest all or a percentage of dividends without incurring brokerage commissions or service charges. The plan is sponsored and administered by Equiniti Trust Company, transfer agent and registrar for MDU Resources. For more information, contact Equiniti Trust Company at 877-536-3553 or visit www.shareowneronline.com.

2018 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 7	March 8	April 1
Second Quarter	June 13	June 14	July 1
Third Quarter	September 12	September 13	October 1
Fourth Quarter	December 12	December 13	January 1, 2019

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT May 8, 2018
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

Jason L. Vollmer
Telephone: 701-530-1755
Email: Jason.Vollmer@mduresources.com

Transfer Agent and Registrar for All Classes of Stock

Equiniti Trust Company
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

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.





Building a Strong America®

Trading Symbol: MDU
www.mdu.com

MDU
LISTED
NYSE

Street Address

1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address

P.O. Box 5650
Bismarck, ND 58506-5650

701-530-1000
866-760-4852

 **MDU RESOURCES**
GROUP, INC.

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)

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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)

Cascade Natural Gas Corporation

Year/Period of Report

End of 201 /Q4

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2017

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NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY	
			Current Year (c)	Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	64,274,782	63,881,403
3	Operating Expenses			
4	Operation Expenses (401)	4-9	43,880,948	43,961,182
5	Maintenance Expenses (402)	4-9	1,628,355	1,478,504
6	Depreciation Expense (403)	10	5,671,347	5,347,120
7	Amortization & Depletion of Utility Plant (404-405)	10	766,241	672,897
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	5,170,826	4,884,659
12	Income Taxes - Federal (409.1)	12	(726,061)	1,123,528
13	Income Taxes - Other (409.1)	13	(129,101)	293,645
14	Provision for Deferred Income Taxes (410.1)	14-21	2,739,613	537,525
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	-	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(8,719)	(11,452)
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)		58,993,449	\$ 58,287,608
20	Net Utility Operating Income (Enter Total of line 2 less 19)		5,281,333	5,593,795

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT		YEAR OF REPORT	
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		(M,D,Y)		Dec. 31, 2017	
STATE OF OREGON - GAS OPERATING REVENUES (ACCOUNT 400)							
Line No.	ACCOUNT (a)	OPERATING REVENUES		MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTOMERS PER MO.	
		CURRENT YEAR (b)	PREVIOUS YEAR (c)	CURRENT YEAR (d)	PREVIOUS YEAR (e)	CURRENT YEAR (f)	PREVIOUS YEAR (g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	\$ 35,525,211	\$ 35,156,436	4,373,150	3,824,641	61,798	60,483
3	481 Commercial and Industrial Sales						
4	Small or Commercial	\$ 20,210,186	\$ 20,355,085	3,096,877	2,620,916	9,947	9,815
5	Large or Industrial	\$ 4,159,797	\$ 4,062,194	713,664	616,629	152	152
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	\$ 59,895,194	\$ 59,573,715	8,183,691	7,062,186	71,897	70,450
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	\$ 59,895,194	\$ 59,573,715	8,183,691	7,062,186	71,897	70,450
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	\$ 59,895,194	\$ 59,573,715				
13	OTHER OPERATING REVENUES						
14	485 Intra-company Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	\$ 182,797	\$ 177,915				
17	489 Revenue from Trans. of Gas of Others	\$ 4,114,884	\$ 4,044,720				
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	\$ 12,000	\$ 12,000				
22	494 Interdepartmental Rents	\$ 25,558	\$ 30,053				
23	495 Other Gas Revenues	\$ 44,349	\$ 43,001				
24	TOTAL Other Operating Revenues	\$ 4,379,588	\$ 4,307,689				
25	TOTAL Gas Operating Revenues	\$ 64,274,782	\$ 63,881,404				
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)	\$ 55,735,397		7,470,027			
29	Main Line Industrial Sales (Incl. Main Line Sales to Public Authorities)	\$ 4,159,797		713,664			
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))	\$ 59,895,194		8,183,691			

NOTES:

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)

Report particulars concerning 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)	MANUFACTURED GAS PROPERTY (d)
	<u>Account 493</u>			
	Stone Bros., Inc.	Northern portion of parking lot at the Hermiston office for a latte stand.	\$ 12,000	12,000.00
			\$ -	-
			\$ -	-
	Total Account 493		\$ 12,000	12,000.00

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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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 CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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)
1	A. Manufactured Gas Production Detail		

NAME OF RESPONDENT		This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
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	35,281,498	30,461,643	
73	804.1 Liquefied Natural Gas Purchases	0	0	
74	805 Other Gas Purchases	0	0	
75	(Less) 805.1 Purchased Gas Cost Adjustments	(4,938,895)	485,265	
76	805.2 Incremental Gas Cost Adjustments	0	0	
77	Total Purchased Gas (Enter Total of lines 67 to 75)	30,342,603	30,946,908	
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	404,388	589,317	
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	(13,303)	(12,580)	
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(13,303)	(12,580)	
95	813 Other Gas Supply Expenses	101,025	170,587	
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	30,834,713	31,694,232	
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	30,834,713	31,694,232	

NAME OF RESPONDENT		This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
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	0
102	815 Maps and Records	0	0	0
103	816 Wells Expenses	0	0	0
104	817 Lines Expense	0	0	0
105	818 Compressor Station Expenses	0	0	0
106	819 Compressor Station Fuel and Power	0	0	0
107	820 Measuring and Regulating Station Expenses	0	0	0
108	821 Purification Expenses	0	0	0
109	822 Exploration and Development	0	0	0
110	823 Gas Losses	0	0	0
111	824 Other Expenses	0	0	0
112	825 Storage Well Royalties	0	0	0
113	826 Rents	0	0	0
114	Total Operation (Enter Total of lines 101 thru 113)	0	0	0
115	Maintenance			
116	830 Maintenance Supervision and Engineering	0	0	0
117	831 Maintenance of Structures and Improvements	0	0	0
118	832 Maintenance of Reservoirs and Wells	0	0	0
119	833 Maintenance of Lines	0	0	0
120	834 Maintenance of Compressor Station Equipment	0	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0	0
122	836 Maintenance of Purification Equipment	0	0	0
123	837 Maintenance of Other Equipment	0	0	0
124	Total Maintenance (Enter Total of lines 116 thru 123)	0	0	0
125	Total Underground Storage Expenses (Total of lines 114 and 124)	0	0	0
126	B. Other Storage Expenses			
127	Operation			
128	840 Operation Supervision and Engineering	0	0	0
129	841 Operation Labor and Expenses	0	0	0
130	842 Rents	0	0	0
131	842.1 Fuel	0	0	0
132	842.2 Power	0	0	0
133	842.3 Gas Losses	0	0	0
134	Total Operation (Enter Total of lines 128 thru 133)	0	0	0
135	Maintenance			
136	843.1 Maintenance Supervision and Engineering	0	0	0
137	843.2 Maintenance of Structures and Improvements	0	0	0
138	843.3 Maintenance of Gas Holders	0	0	0
139	843.4 Maintenance of Purification Equipment	0	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0	0
142	843.7 Maintenance of Compressor Equipment	0	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0	0
144	843.9 Maintenance of Other Equipment	0	0	0
145	Total Maintenance (Enter Total of lines 136 thru 144)	0	0	0
146	Total Other Storage Expenses (Enter Total of lines 134 and 145)	0	0	0

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0	0
153	844.5 Measuring and Regulation Labor and Expenses	0	0	0
154	844.6 Compressor Station Labor and Expenses	0	0	0
155	844.7 Communication System Expenses	0	0	0
156	844.8 System Control and Load Dispatching	0	0	0
157	845.1 Fuel	0	0	0
158	845.2 Power	0	0	0
159	845.3 Rents	0	0	0
160	845.4 Demurrage Charges	0	0	0
161	(Less) 845.5 Wharfage Receipts - Credit	0	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0	0
163	846.1 Gas Losses	0	0	0
164	846.2 Other Expenses	0	0	0
165	Total Operation (Enter Total of lines 149 thru 164)	0	0	0
166	Maintenance			
167	847.1 Maintenance Supervision and Engineering	0	0	0
168	847.2 Maintenance of Structures and Improvements	0	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0	0
173	847.7 Maintenance of Communication Equipment	0	0	0
174	847.8 Maintenance of Other Equipment	0	0	0
175	Total Maintenance (Enter Total of lines 167 thru 174)	0	0	0
176	Total Liquefied Nat Gas Terminaling & Process Exp (Lines 165 & 175)	0	0	0
177	Total Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0	0
178	3. TRANSMISSION EXPENSES			
179	Operation			
180	850 Operation Supervision and Engineering	0	0	0
181	851 System Control and Load Dispatching	0	0	0
182	852 Communication System Expenses	0	0	0
183	853 Compressor Station Labor and Expenses	0	0	0
184	854 Gas for Compressor Station Fuel	0	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0	0
186	856 Mains Expenses	0	0	0
187	857 Measuring and Regulating Station Expenses	0	0	0
188	858 Transmission and Compression of Gas by Others	0	0	0
189	859 Other Expenses	0	0	0
190	860 Rents	0	0	0
191	Total Operation (Enter Total of lines 180 thru 190)	0	0	0
192	Maintenance			
193	861 Maintenance Supervision and Engineering	0	0	0
194	862 Maintenance of Structures and Improvements	0	0	0
195	863 Maintenance of Mains	0	0	0
196	864 Maintenance of Compressor Station Equipment	0	0	0
197	865 Maintenance of Measuring and Reg. Station Equipment	0	0	0
198	866 Maintenance of Communication Equipment	0	0	0
199	867 Maintenance of Other Equipment	0	0	0
200	Total Maintenance (Enter Total of lines 193 thru 199)	0	0	0
201	Total Transmission Expenses (Enter Total of lines 191 and 200)	0	0	0

NAME OF RESPONDENT		This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)				
LINE NO.	ACCOUNT (a)	CUURRENT YEAR (b)	PREVIOUS YEAR (c)	
202	4. DISTRIBUTION EXPENSES			
203	Operation			
204	870 Operation Supervision and Engineering	735,994	502,211	
205	871 Distribution Load Dispatching	112,679	140,032	
206	872 Compressor Station Labor and Expenses	0	0	
207	873 Compressor Station Fuel and Power	0	0	
208	874 Mains and Services Expenses	1,223,950	1,073,812	
209	875 Measuring and Regulating Station Expenses - General	186,913	223,345	
210	876 Measuring and Regulating Station Expenses - Industrial	19,763	12,145	
211	877 Measuring & Regulating Station Exp - City Gate Check Station	458,032	0	
212	878 Meter and House Regulator Expenses	448,687	543,771	
213	879 Customer Installations Expenses	0	451,504	
214	880 Other Expenses	1,599,521	1,350,048	
215	881 Rents	33,201	20,039	
216	Total Operation (Enter Total of lines 204 thru 215)	4,818,740	4,316,907	
217	Maintenance			
218	885 Maintenance Supervision and Engineering	147,320	109,200	
219	886 Maintenance of Structures and Improvements	179	487	
220	887 Maintenance of Mains	336,082	354,201	
221	888 Maintenance of Compressor Station Equipment	(1,269)	781	
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	53,968	33,903	
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	8,477	60,495	
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	0	
225	892 Maintenance of Services	476,389	331,052	
226	893 Maintenance of Meters and House Regulators	417,681	375,529	
227	894 Maintenance of Other Equipment	176,967	57,136	
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,615,794	1,322,784	
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	6,434,534	5,639,691	
230	5. CUSTOMER ACCOUNTS EXPENSES			
231	Operation			
232	901 Supervision	12,405	1,621	
233	902 Meter Reading Expenses	192,860	196,877	
234	903 Customer Records and Collection Expenses	1,461,608	1,344,568	
235	904 Uncollectible Accounts	237,848	166,036	
236	905 Miscellaneous Customer Accounts Expenses	208	372	
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,904,929	1,709,474	
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
239	Operation			
240	907 Supervision	0	0	
241	908 Customer Assistance Expenses	98,401	603,418	
242	909 Informational and Instructional Expenses	5,684	9,386	
243	910 Miscellaneous Customer Service and Informational Expenses	17,119	0	
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	121,204	612,804	
245	7. SALES EXPENSES			
246	Operation			
247	911 Supervision	0	0	
248	912 Demonstrating and Selling Expenses	0	0	
249	913 Advertising Expenses	913	2,313	
250	916 Miscellaneous Sales Expenses	0	0	
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	913	2,313	

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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)	
252	8. ADMINISTRATIVE AND GENERAL EXPENSES			
253	Operation			
254	920 Administrative and General Salaries	2,264,862	1,947,880	
255	921 Office Supplies and Expenses	1,009,853	815,786	
256	(Less) 922 Administrative Expenses Transferred - Cr.	(96,290)	(97,825)	
257	923 Outside Services Employed	286,641	566,996	
258	924 Property Insurance	17,974	19,840	
259	925 Injuries and Damages	420,394	419,184	
260	926 Employee Pensions and Benefits	1,708,831	1,556,729	
261	927 Franchise Requirements	0	0	
262	928 Regulatory Commission Expenses	0	0	
263	(Less) 929 Duplicate Charges - Cr.	0	0	
264	930.1 General Advertising Expenses	10,711	13,966	
265	930.2 Miscellaneous General Expenses	213,092	264,144	
266	931 Rents	364,381	423,272	
267	Total Operation (Enter Total lines 254 thru 266)	6,200,449	5,929,972	
268	Maintenance			
269	935 Maintenance of General Plant	12,561	11,098	
270	Total Administrative and General Exp (Total of lines 267 and 269)	6,213,010	5,941,070	
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	45,509,303	45,599,584	

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	30,834,713	0	30,834,713
280	Total Production	30,834,713	0	30,834,713
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	4,818,740	1,615,794	6,434,534
286	Customer Accounts Expenses	1,904,929	0	1,904,929
287	Customer Service and Informational Expenses	121,204	0	121,204
288	Sales Expenses	913	0	913
289	Admin and General Expenses	6,200,449	12,561	6,213,010
290	Total Gas O. & M. Expenses	43,880,948	1,628,355	45,509,303

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT	YEAR OF REPORT		
CASCADE NATURALGAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017		
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			766,241			766,241
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	113,173					113,173
9	Distribution Plant	5,227,675					5,227,675
10	General Plant	330,498					330,498
11	Common Plant - Gas						-
12							
13							
14							
15							
16							
17							
18							
19	TOTAL	5,671,346	-	766,241	-	-	6,437,587

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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STATE OF OREGON - ALLOCATED TAXES, OTHER THAN INCOME TAXES (Account 408.1)

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,526,316
2	Payroll Taxes	599,770
3	Oregon PUC Regulatory Fee	191,644
4	Oregon Department of Energy Fee	81,573
5	City Franchise Taxes	2,742,046
6	Miscellaneous Taxes	29,477
TOTAL (Must agree with page 1, line 11)		5,170,826

NAME OF RESPONDENT		This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
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.	PARTICULARS (Details) (a)		Amount (b)	
1	Gas Operating Revenues		290,448,860	
2	Operations and Maintenance Expenses		(229,082,933)	
3	Taxes, Other than Income		(29,057,099)	
4	State Income (Excise) Tax		(21,289)	
5	Interest		(12,404,037)	
6	Other Income		471,096	
7	Federal Income Tax Depreciation		(26,547,005)	
8	Other Additions (Subtractions) to Derive Taxable Income			
9	CIAC		494,111	
10	Book depreciation included in O&M		28,190,594	
11	Tax Gain (loss) on disposal of assets		(1,228,011)	
12	Vacation Accrual adjustment		121,753	
13	Retiree Medical Accrual adjustment		3,232	
14	Amort of loss on reacquired debt (4281)		40,971	
15	SFAS No.87 pension plan accrual		(199,333)	
16	SFAS No.87 accrual-SERP DO add back bk expense		150,295	
17	SERP-perm difference piece		(735,544)	
18	FAS158 Adjustment		(35,420)	
19	Bad Debt Adjustment		170	
20	Charitable Contributions (5981.4261)		-	
21	Permanent diff's			
22	50 % of business meals & entertainment		159,273	
23	Penalties (5984)		-	
24	Lobbying (5912.4264)		128,933	
25	Tax exempt interest		-	
26	Interest capitalized adj (IRS>books)		194,318	
27	Customer Advances - 2520.000 to 2520.2991		572,669	
28	CC&B Deduction		-	
29	Repairs Deduction		(1,074,599)	
30	Section 174 costs		(771,889)	
31	Legal Reserve		-	
32	263A Adjustment - UNICAP		2,385	
33	401K Dividends (MDUR)		(155,207)	
34	Severance accrual adjustment		-	
35	STIP accrual adjustment		(1,045,840)	
36	Deferred Gas Costs		(11,278,210)	
37	Prepaid Expenses		(102,453)	
38	Performance Share Perm		(611,520)	
39	Royalty Income (15% of royalty income receipts)		(1,617)	
40	MGP expense		(663,163)	
41	MAOP Deferred Costs		(4,351,630)	
42	Federal Tax Net Income		1,611,861	
43	Show Computation of Tax:			
44	Federal Tax Rate		35%	
45	Estimated Federal Tax		564,151	
46	Adjustments to Estimated Federal Tax			
47	Difference between 12/31/16 accrual and tax return		(2,574,088)	
48	Prior year adjustments		(667,189)	
49	Tax Retorm		441,582	
50	Provision for Current Federal Income Tax		(2,235,544)	
51	Allocated to:		Total	
52	Washington	409.1 (1,508,118)	409.2 (1,024)	(1,509,142)
53	Oregon	(726,061)	(341)	(726,402)
54	Total	(2,234,179)	(1,365)	(2,235,544)
55				

NAME OF RESPONDENT		This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
RENT STATE INCOME (EXCISE) TAX EXPENSE (Account 409.1)				
<p>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).</p> <p>2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.</p> <p>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.</p> <p>4. Minor amounts of other additions (subtractions) may be grouped.</p>				
Line No.	Particulars (Details) (a)	Amount (b)		
1	Gas Operating Revenues	290,448,860		
2	Operations and Maintenance Expenses	(229,082,933)		
3	Taxes, Other than Income	(29,057,099)		
4	State Income (Excise) Tax			
5	Interest	(12,404,037)		
6	Other Income	471,096		
7	Federal Income Tax Depreciation	(27,000,476)		
8	Other Additions (Subtractions) to Derive Taxable Income			
9	CIAC	494,111		
10	Book depreciation included in O&M	28,190,594		
11	Tax Gain (loss) on disposal of assets:	(1,228,151)		
12	Vacation Accrual adjustment	121,753		
13	Retiree Medical Accrual adjustment	3,232		
14	Amort of loss on reacquired debt (4281)	40,971		
15	SFAS No.87 pension plan accrual	(199,333)		
16	SFAS No.87 accrual-SERP DO add back bk expense	150,295		
17	SERP-perm difference piece	(735,544)		
18	FAS158 Adjustment	(35,420)		
19	Bad Debt Adjustment	170		
20	Charitable Contributions (5981.4261)	-		
21	Permanent diff's			
22	50 % of business meals & entertainment	159,273		
23	Penalties (5984)	-		
24	Lobbying (5912.4264)	128,933		
25	Tax exempt interest	-		
26	Interest capitalized adj (IRS>books)	194,318		
27	Customer Advances - 2520.000 to 2520.2991	572,669		
28	CC&B Deduction	-		
29	Repairs Deduction	(1,074,599)		
30	Section 174 Costs	(771,889)		
31	Legal Reserve	-		
32	263A Adjustment - UNICAP	2,385		
33	401K Dividends (MDUR)	(155,207)		
34	Severance accrual adjustment	-		
35	STIP accrual adjustment	(1,045,840)		
36	Deferred Gas Costs	(11,278,210)		
37	Prepaid Expenses	(102,453)		
38	Performance Share Perm	(611,520)		
39	Royalty Income (15% of royalty income receipts)	(1,617)		
40	MGP expense	(663,163)		
41	MAOP Deferred Costs	(4,351,630)		
42	Federal Tax Net Income	1,179,539		
43	Oregon Apportionment Rate	23.7483%		
44	State Tax Net Income	280,120		
45	Show Computation of Tax:			
46	State Tax Rate	7.6%		
47		21,289		
48	Adjustments to Estimated Federal Tax			
49	Difference between 12/31/16 accrual and tax return	(147,330)		
50	Prior year adjustments	(25,171)		
51	Tax Return	23,190		
52	Provision for Current Federal Income Tax	(128,022)		
53	Allocated to:	<u>409.1</u>	<u>409.2</u>	Total
54	Oregon	(129,101)	1,079	(128,022)
55				

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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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)	Amounts Credited to Account 411.1 (d)
1	Electric			
2				
3	Other			
4	TOTAL ELECTRIC			
5	Gas	26,488,327	(15,506,308)	-
6				
7	Other	-		
8	TOTAL GAS	26,488,327	(15,506,308)	-
9	Other (Specify)	-		
10	TOTAL (Account 190)	26,488,327	(15,506,308)	-
11	Classification of Totals			
12	Federal Income Tax	25,173,398	(15,412,760)	-
13	State Income Tax	1,314,929	(93,548)	-
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	See Below	(12,189,952)	-
18	Federal Income Tax - Oregon	See Below	(3,222,808)	-
19	State Income Tax - Oregon	1,314,929	(93,548)	-
20				
21				
22				

The federal balance in account 190 relating to customer advances 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 Customer Advances	-	1,055,801
Washington allocation factor	76.55%	77.16%
Washington Allocated balance relating to Customer Advances	-	814,656
Oregon allocation factor	23.45%	22.84%
Oregon Allocated balance relating to Customer Advances	-	241,145
Remaining balance to be allocated on 3-factor	25,173,398	13,975,533
Oregon allocation factor	24.73%	24.96%
Oregon allocation	6,225,381	3,488,293
Plus Oregon Allocation of Customer Advances related balance	-	241,145
Total Oregon Allocated Balance	6,225,381	3,729,438

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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 (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	DEBITS		CREDITS			
		Account No. (g)	Amount (h)	Account No. (l)	Amount (j)		
							1
							2
							3
							4
-	-	Regulatory accounts related to FAS 158 and OR rate change adjustments	25,603,543	Regulatory accounts related to FAS 158 and OR rate change adjustments	20,242,427	16,343,135	5
							6
						-	7
-	-		25,603,543		20,242,427	16,343,135	8
						-	9
-	-		25,603,543		20,242,427	16,343,135	10
							11
-	-		24,515,367		19,244,671	15,031,334	12
-	-		1,088,176		997,756	1,311,801	13
-	-		-		-	-	14
							15
							16
-	-		19,389,204		15,220,610	See Below	17
-	-		5,126,163		4,024,061	See Below	18
-	-		1,088,176		997,756	1,311,801	19
							20
							21
							22

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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 columnar order:

- | | |
|---|--|
| (a) State each certification number with a brief description of property. | (c) Date amortization for tax purposes commenced. |
| (b) Total and amortizable cost of such property. | (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 CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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 (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	DEBITS		CREDITS			
		Account No. (g)	Amount (h)	Account No. (l)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
-	-	-	-	-	-	-	8
							9
							10
							11
							12
							13
							14
-	-	-	-	-	-	-	15
							16
-	-	-	-	-	-	-	17
							18
-	-		-		-	-	19
-	-		-		-	-	20
-	-		-		-	-	21

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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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	(100,067,346)	(2,341,555)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(100,067,346)	(2,341,555)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 282) Lines 5 thru 8	(100,067,346)	(2,341,555)	-
10	Classification of Totals			
11	Federal Income Tax	(95,651,640)	(2,184,789)	-
12	State Income Tax	(4,415,706)	(156,766)	-
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	See Below	(1,727,950)	-
	Federal Income Tax - Oregon	See Below	(456,839)	-
	State Income Tax - Oregon	(4,415,706)	(156,766)	-
	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	(98,089,299)	(100,214,084)	
	Washington allocation factor	76.55%	77.16%	
	Washington Allocated balance relating to utility plant for ratemaking	(75,087,358)	(77,325,187)	
	Oregon allocation factor	23.45%	22.84%	
	Oregon Allocated balance relating to utility plant for ratemaking	(23,001,941)	(22,888,897)	
	Remaining balance to be allocated on Utility Plant	2,437,659	51,800,095	
	Oregon allocation factor	22.76%	22.55%	
	Oregon allocation	554,811	11,680,921	
	Plus Oregon Allocation of utility plant for ratemaking related balance	(23,001,941)	(22,888,897)	
	Total Oregon Allocated Balance	(22,447,130)	(11,207,976)	

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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 (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	DEBITS		CREDITS			
		Account No. (g)	Amount (h)	Account No. (i)	Amount (j)		
							1
						-	2
-	-	182.3 & 254	52,484,094	182.3 & 254	2,154,130	(52,078,937)	3
						-	4
-	-		52,484,094		2,154,130	(52,078,937)	5
						-	6
							7
							8
-	-		52,484,094		2,154,130	(52,078,937)	9
							10
-	-	254	51,472,659	254	2,050,219	(48,413,989)	11
-	-	182.3	1,011,435	182.3	103,911	(3,664,948)	12
-	-		-		-	-	13
-	-		40,709,726		1,621,518	See Below	
-	-		10,762,933		428,701	See Below	
-	-		1,011,435		103,911	(3,664,948)	

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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)	Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(36,157,096)	6,713,310	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(36,157,096)	6,713,310	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(36,157,096)	6,713,310	-
10	Classification of Totals			
11	Federal Income Tax	(34,048,055)	6,983,136	-
12	State Income Tax	(2,109,041)	(269,826)	-
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	See below	5,522,962	-
	Federal Income Tax - Oregon	See below	1,460,174	-
	State Income Tax - Oregon	(2,109,041)	(269,826)	-
	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	(284,789)	(161,931)	
	Washington allocation factor	76.55%	77.16%	
	Washington Allocated balance relating to Debt Refinancing	(218,006)	(124,946)	
	Oregon allocation factor	23.45%	22.84%	
	Oregon Allocated balance relating to Debt Refinancing	(66,783)	(36,985)	
	Remaining balance to be allocated on 3-factor	(33,763,266)	(22,899,689)	
	Oregon allocation factor	24.73%	24.96%	
	Oregon allocation	(8,349,656)	(5,715,762)	
	Plus Oregon Allocation of Debt refinancing related balance	(66,783)	(36,985)	
	Total Oregon Allocated Balance	(8,416,439)	(5,752,747)	

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT	YEAR OF REPORT		
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017		
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.
Amounts Debited Account 410.2 (e)	Amounts Credited Account 411.2 (f)	DEBITS		CREDITS			
		Account No.	Amount	Account No.	Amount		
		(g)	(h)	(i)	(j)	(k)	
							1
							2
-	-	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	35,333,776	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	31,268,367	(25,378,377)	3
						-	4
-	-		35,333,776		31,268,367	(25,378,377)	5
						-	6
							7
							8
-	-		35,333,776		31,268,367	(25,378,377)	9
							10
-	-		33,975,469		29,972,170	(23,061,620)	11
-	-		1,358,307		1,296,197	(2,316,757)	12
-	-		-		-	-	13
-	-		26,871,198		23,704,989	See below	
-	-		7,104,271		6,267,181	See below	
-	-		1,358,307		1,296,197	(2,316,757)	

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, 2017

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 (a)	Balance at Beginning of Year (b)	Deferred For Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year of (h)	Average period of Allocation to Income (i)
			Account No (c)	Amount (d)	Account No (e)	Amount (f)			
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(8,719)		ALLOCATED	23 Years
6	Total	0		0		(8,719)			
7	Other (list separately and show 3%, 4%, 7% & 10% and TOTAL)								
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

NOTES

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT		YEAR OF REPORT	
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)		Dec. 31, 2017	
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 (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	200,511,039		200,511,039			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	9,332,301		9,332,301			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	209,843,340	-	209,843,340	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,452,858		1,452,858			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	211,296,198	-	211,296,198	-		-
14	Accumulated Prov For Depr., Amort., & Depl.	(96,644,875)		(96,644,875)			
15	Net Utility Plant (Line 13 less 14)	114,651,323	-	114,651,323	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(96,626,376)		(96,626,376)			
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	(18,499)		(18,499)			
22	Total In-Service (Total of lines 18 thru 21)	(96,644,875)	-	(96,644,875)	-		-
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	Abandonment 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)	(96,644,875)	-	(96,644,875)	-		-

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT		YEAR OF REPORT	
CASCADE NATURAL GAS CORPORATION		<input checked="" type="checkbox"/> An Original <input type="checkbox"/> A Resubmission		(M,D,Y)		Dec. 31, 2017	

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		ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
		BEG. OF YEAR (b)	END OF YEAR (g)					
1	1. Intangible Plant							
2	301 Organization	73,667						73,667
3	302 Franchises and Consents							
4	303 Miscellaneous Intangible Plant	113,374		2,834,446				2,947,820
5	TOTAL Intangible Plant	187,041		2,834,446				3,021,487
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) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)		Dec. 31, 2017	
STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)							
<p>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 distributed in column (f) to primary account classifications.</p> <p>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.</p> <p>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.</p>							
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	Compressor Equipment	-					-
34	Gas Measuring and Regulating Equipment	-					-
35	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	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	Land and Land Rights	-					-
57	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) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)		Dec. 31, 2017	
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 Liquefied Natural Gas, Terminating & Processing Plant	-	-	-	-	-	-
76	TOTAL Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
77	4. Transmission Plant						
78							
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	ARO - Transmission	24,733	241				24,974
87	TOTAL Transmission Plant	5,900,639	241	-	-	-	5,900,880
88	5. Distribution Plant						
89	374 Land and Land Rights	220,912	155,968				376,880
90	375 Structures and Improvements	363,785					363,785
91	376 Mains	87,012,896	5,695,453	(48,064)			92,660,285
92	377 Compressor Station Equipment	-					-
93	378 Measuring and Regulating Equipment - General	8,710,463	1,631,674				10,342,137
94	379 Measuring and Regulating Equipment - City Gate	-					-
95	380 Services	48,476,792	2,917,874	(44,147)			51,350,519
96	381 Meters	14,135,490	692,039	(263,896)	112,544		14,676,177
97	382 Meter Installations	8,433,777	678,093	(132)		(3,232)	9,108,506
98	383 House Regulators	2,609,329	166,143	(90,078)	20,775		2,706,169
99	384 House Regulator Installations	-					-
100	385 Industrial Measuring and Regulating Station Equipment	1,828,167	47,827	(1,358)		3,232	1,877,868
101	386 Other Property on Customers' Premises	-					-
102	387 Other Equipment	-					-
102.a	ARO - Distribution	3,652,001	714,394	(6,785)			4,359,610
103	TOTAL Distribution Plant	175,443,612	12,699,465	(454,460)	133,319	-	187,821,936

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT			YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)			Dec. 31, 2017
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	493,301					493,301
106	390 Structures and Improvements	4,503,032					4,503,032
107	391 Office Furniture and Equipment	182,715					182,715
108	392 Transportation Equipment	3,546,884	366,715	(123,447)			3,790,152
109	393 Stores Equipment	-					-
110	394 Tools, Shop and Garage Equipment	1,274,964	10,787	(11,124)			1,274,627
111	395 Laboratory Equipment	-					-
112	396 Power Operated Equipment	947,966	951,053	(649,899)			1,249,120
113	397 Communication Equipment	1,344,959	291,393	(37,471)			1,598,881
114	398 Miscellaneous Equipment	7,209					7,209
115	SUBTOTAL	12,301,030	1,619,948	(821,941)	-	-	13,099,037
116	Other Tangible Property	-					-
117	TOTAL General Plant	12,301,030	1,619,948	(821,941)	-	-	13,099,037
118	TOTAL (Accounts 101 and 106)	193,832,322	17,154,100	(1,276,401)	133,319	-	209,843,340
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	193,832,322	17,154,100	(1,276,401)	133,319	-	209,843,340

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE (Account 105)

- 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.
- 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
2				
3				
4				
5				
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39				
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45				
46				
47				
48				
49				
50				
51				
52	TOTALS -	0	0	0

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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,	1,452,858		
7	meter sets and telemetering, and etc.			
8				
9				
10				
11				
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42				
43	TOTAL -	1,452,858	0	

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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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	(91,873,519)	(91,873,519)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(5,509,477)	(5,509,477)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(265,247)	(265,247)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(51,237)	(51,237)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (Enter total of lines 3 thru 8)	(5,825,961)	(5,825,961)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	1,276,401	1,276,401		
12	Cost of Removal	238,582	238,582		
13	Salvage (credits)	(538,166)	(538,166)		
14	TOTAL Net Charges for Plant Retired (enter Total of Lines 11 thru 13)	976,817	976,817		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	139,473	139,473		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(43,186)	(43,186)		
16					
17	Balance End of Year (Enter Total of Lines 1, 9, 14, 15, & 16)	(96,626,376)	(96,626,376)		

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 Terminating and Proc. Plant	-	-		
24	Transmission	(3,515,483)	(3,515,483)		
25	Distribution	(89,769,102)	(89,769,102)		
26	General	(3,738,269)	(3,738,269)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	470,145	470,145		
27	TOTAL (Enter Total of Lines 18 thru 26)	(96,626,376)	(96,626,376)		

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) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017		
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 (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	13,609,905		13,609,905			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	420,931		420,931			
7	Experimental Plant Unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	14,030,836	-	14,030,836	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	286,904		286,904			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Lines 8 thru 12)	14,317,740	-	14,317,740	-		-
14	Accumulated Prov For Depr. Amort, & Depl.	(6,320,345)		(6,320,345)			
15	Net Utility Plant (Line 13 less 14)	7,997,395	-	7,997,395	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(2,879,027)		(2,879,027)			
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	(3,441,318)		(3,441,318)			
22	Total In-Service (Lines 18 thru 21)	(6,320,345)	-	(6,320,345)	-		-
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	Abandonment 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)	(6,320,345)	-	(6,320,345)	-		-

NAME OF RESPONDENT		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		DATE OF REPORT (M,D,Y)	YEAR OF REPORT		
CASCADE NATURAL GAS CORPORATION				(M,D,Y)	Dec. 31, 2017		
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	37,607			350		37,957
3	302 Franchises and Consents	-					-
4	303 Miscellaneous Intangible Plant	7,961,597	1,144,675		74,046		9,180,318
5	TOTAL Intangible Plant	7,999,204	1,144,675	-	74,396	-	9,218,275
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 Easement 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	Land and Land Rights	-					-
29	Structures and Improvements	-					-
30	Extraction and Refining Equipmnet	-					-
31	Pipe Lines	-					-
32	Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		DATE OF REPORT (M,D,Y)	YEAR OF REPORT		
CASCADE NATURAL GAS CORPORATION				(M,D,Y)	Dec. 31, 2017		
STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Cont)							
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 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 (Cont)						
	Products Extraction Plant (Cont)						
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	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) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(M,D,Y)			Dec. 31, 2017
STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Cont'd)							
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 Liquefied Natural Gas, Terminating & Processing Plant	-	-	-	-	-	-
76	Gas, Terminating & 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	23,468	-	-	-	219	23,687
90	375 Structures and Improvements	98,719	-	-	-	918	99,637
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	122,187	-	-	1,137	-	123,324

NAME OF RESPONDENT		This Report Is:		DATE OF REPORT			YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original	STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Cont)			(M,D,Y)	Dec. 31, 2017
		(2) <input type="checkbox"/> A Resubmission					
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	Land and Land Rights	236,101			2,195		238,296
106	Structures and Improvements	1,449,759	8,892		13,483		1,472,134
107	Office Furniture and Equipment	1,688,577	63,732		15,705		1,768,014
108	Transportation Equipment	479,148	10,872	(16,234)	4,456		478,242
109	Stores Equipment	10,656			99		10,755
110	Tools, Shop, and Garage Equipment	453,238	18,439	(471)	4,215		475,421
111	Laboratory Equipment	23,959			222		24,181
112	Power Operated Equipment	(17,009)	(405)		(158)		(17,572)
113	Communication Equipment	222,847			2,072		224,919
114	Miscellaneous Equipment	14,710			137		14,847
115	SUBTOTAL	4,561,986	101,530	(16,705)	42,426	-	4,689,237
116	Other Tangible Property	-					-
117	TOTAL General Plant	4,561,986	101,530	(16,705)	42,426	-	4,689,237
118	TOTAL (Accounts 101 and 106)	12,683,377	1,246,205	(16,705)	117,959	-	14,030,836
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	12,683,377	1,246,205	(16,705)	117,959	-	14,030,836

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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
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46	TOTALS -	0	0	0

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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	286,904		
4				
5				
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48	TOTAL -	286,904	0	

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) Dec. 31, 2017	YEAR OF REPORT Dec. 31, 2017
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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	(2,713,988)	(2,713,988)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(161,869)	(161,869)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(27,565)	(27,565)		
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)	(189,434)	(189,434)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	16,706	16,706		
12	Cost of Removal	-	-		
13	Salvage (credits)	(6,272)	(6,272)		
14	TOTAL Net Charges for Plant Retired (enter Total of Lines 11 thru 13)	10,434	10,434		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	39,381	39,381		
15.02	Adjustment Due to Change in Allocation Rate	(25,420)	(25,420)		
16					
17	Balance End of Year (Enter Total of Lines 1, 9, 14, 15, & 16)	(2,879,027)	(2,879,027)		

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	-	-		
25	Distribution	(104,582)	(104,582)		
26	General	(2,863,427)	(2,863,427)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	88,982	88,982		
27	TOTAL (Total of Lines 18 thru 26)	(2,879,027)	(2,879,027)		

NOTE:
Row 15 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017	
STATE OF OREGON - GAS STORED (ACCOUNT 117, 164.1, 164.2 AND 164.3)						
<p>1 Report below the information called for concerning inventories of gas stored.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>7 Pressure base of gas volumes reported in this schedule is 14.73 psia at 60" F.</p>						
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					
3	(contract account)					
4	Gas withdrawn from storage					
5	(contra account)			\$ 131,185		\$ 131,185
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					Not allocated
19	Amount per Mcf					Not allocated
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					51,611
31	Amount per Mcf					2.54
32	Cost basis of withdrawals:					
33	Specify: average cost, lifo, fifo, (Explain any change in					
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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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
STATE OR OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804.1 and 805)			
<p>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.)</p> <p>2. Provide subheadings and totals for prescribed accounts as follows:</p> <ul style="list-style-type: none"> 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 <p>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.</p> <p>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.</p> <p>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 discontinued 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.</p> <p>5. Column instructions are as follows:</p> <p><u>Columns (a) and (d)</u> - 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.</p> <p><u>Column (b)</u> - 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.</p> <p><u>Column (c)</u> - State the net rate in cents per Mcf as of December 31 for the reported year, applicable to the volume shown in Column (k).</p>	<p>The net rate includes all applicable deductions and downward adjustments. The rate is effective and is filed pursuant to applicable statutes and regulations and (as to FERC rates schedules) permitted by the Commission to become effective.</p> <p><u>Columns (e) and (f)</u> - 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.</p> <p><u>Column (g)</u> - 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.</p> <p><u>Column (h)</u> - 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).</p> <p><u>Column (i)</u> - 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.</p> <p><u>Column (j)</u> - 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.</p> <p><u>Column (k)</u> - 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.</p> <p><u>Column (l)</u> - State the dollar amount (omit cents) paid and previously paid for the volumes of gas shown in Col. (k).</p> <p><u>Column (m)</u> - State the average cost per MCF to the nearest hundredth of a cent. (Column (l) divided by Column (k) multiplied by 100.)</p>		

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		(M,D,Y)	Dec. 31, 2017

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		Date of Contract (l)	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.
			No. (g)	Suffix (h)						
						10.75	8,242,803	\$ 21,735,779	263.69	1
								\$ 478,933	n/a	2
								\$ 8,127,891	n/a	3
										4
										5
										6
										7
							8,242,803	\$ 30,342,603	n/a	8
										9
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NAME OF RESPONDENT		This Report Is:		DATE OF REPORT		YEAR OF REPORT	
CASCADE NATURAL GAS CORPORATION		<input checked="" type="checkbox"/> (1) An Original <input type="checkbox"/> (2) A Resubmission		(M,D,Y)		Dec. 31, 2017	

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 used 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			Manufactured Gas	
			MCF OF GAS USED (14.73 PSIA AT 60 °F) (c)	AMOUNT OF CREDIT (d)	AMOUNT PER MCF (CENTS) (e)	MCF OF GAS USED (14.73 PSIA AT 60 °F) (f)	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 (Report separately for each principal use. Group minor uses).	812	4,874 \$	13,303	0	0	0
6							
7							
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12							
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22	TOTAL		4,874 \$	13,303			

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NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) 	YEAR OF REPORT Dec. 31, 2017
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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		8,237,937
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		8,237,937
14	Gas of others received for transportation		18,162,209
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		146,283
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		26,546,429

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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		713,663
39	(ii) Other distribution system sales		7,470,027
40	TOTAL DISTRIBUTION SYSTEM SALES		8,183,690
41	d. Interdepartmental sales		
42	TOTAL SALES		8,183,690
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		18,162,209
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		18,162,209
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		4,866
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		26,350,765
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		195,664
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		195,664
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		26,546,429

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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STATE OF OREGON - Miscellaneous General Expenses (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.	248,538	62,115	186,423
2	Experimental and general research expenses.			
	a. Gas Research Institute (GRI)			
	b. Other			
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the respondent			
4				
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex and MDU for CNGC's share of corporate banking fees)	357,889	89,329	268,560
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	233,017	58,161	174,856
7	Miscellaneous under \$250,000	18,076	3,488	14,588
8				
9				
10				
	TOTAL	857,520	213,093	644,427

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y) 	YEAR OF REPORT Dec. 31, 2017
STATE OF OREGON - POLITICAL ADVERTISING				
<p>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</p> <p>2. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged.</p> <p>3. Report whole dollars only. Provide a total for each account and a grand total.</p>				
LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)	
1	NONE			
	TOTAL			

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.				
<p>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."</p> <p>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.</p>				
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	1,075,560	268,460
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	15,234	3,802
3	MDU/MDUR Allocated - approved in Order 07-418	426.4	(315,562)	(78,764)
4	MDU/MDUR Allocated - approved in Order 07-418	426.4	1,029	257
5	MDU/MDUR Allocated - approved in Order 07-418	813	116,821	29,158
6	MDU/MDUR Allocated - approved in Order 07-418	875	104,350	26,046
7	MDU/MDUR Allocated - approved in Order 07-418	880	580,618	144,922
8	MDU/MDUR Allocated - approved in Order 07-418	901	29,131	7,271
9	MDU/MDUR Allocated - approved in Order 07-418	902	183,728	45,858
10	MDU/MDUR Allocated - approved in Order 07-418	903	5,743,496	1,433,576
11	MDU/MDUR Allocated - approved in Order 07-418	904	13,270	3,312
12	MDU/MDUR Allocated - approved in Order 07-418	909	19,171	4,785
13	MDU/MDUR Allocated - approved in Order 07-418	913	26	7
14	MDU/MDUR Allocated - approved in Order 07-418	920	5,241,014	1,308,157
15	MDU/MDUR Allocated - approved in Order 07-418	921	2,270,703	566,768
16	MDU/MDUR Allocated - approved in Order 07-418	922	(168,391)	(42,030)
17	MDU/MDUR Allocated - approved in Order 07-418	923	181,630	45,335
18	MDU/MDUR Allocated - approved in Order 07-418	925	112	28
19	MDU/MDUR Allocated - approved in Order 07-418	926	36,732	9,168
20	MDU/MDUR Allocated - approved in Order 07-418	930.1	19,583	4,888
21	MDU/MDUR Allocated - approved in Order 07-418	930.2	240,894	60,127
22	MDU/MDUR Allocated - approved in Order 07-418	931	1,349,082	336,731
23	Other Services	VAR	1,299,737	349,221
TOTALS			18,037,967	4,527,083

NAME OF RESPONDENT		This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017
STATE OF OREGON - Donations and Memberships				
<p>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:</p> <p>a. Contributions to and memberships in charitable organizations d. Commercial and trade organizations b. Organizations of the utility industry e. All other organizations and kinds of donations and c. Technical and professional organizations</p> <p>2. List donations by type and group by the account charged. Report whole dollars only. Provide a total for each group of donations.</p>				
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	MDU Resources Foundation (Bismarck ND)	426.1	107,522	26,837
3	United Way (WA and OR)	426.1	3,052	762
4	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,480
5	Neighbor Impact (Redmond OR)	426.1	1,000	1,000
6	Other Organizations (33 organizations)	426.1/880.0/908.0	19,104	10,749
7	Total contributions to and memberships in charitable organizations		180,678	51,828
8	(b) Organizations of the Utility Industry:			
9	American Gas Association (Washington D.C.)	426.1/426.4/930.2	114,046	28,466
10	Northwest Gas Association (West Linn, OR)	930.2	62,449	15,587
11	Other Organizations (7 organizations)	908.0/930.2/921.0	49,867	13,148
12	Total contributions to Organizations of the Utility Industry		226,362	57,201
13	(c) Technical and Professional Organizations			
14	National Association of Corrosion Engineers (Houston, TX)	921.0	2,000	499
15	Other Organizations (15 organizations)	921.0	2,689	671
16	Total contributions to Professional Organizations		4,689	1,170
17	(d) Commercial and Trade Organizations			
18	Association of Washington Business (Olympia, WA)	930.2/921.0	38,000	9,485
19	Chamber of Commerce-15 (WA and OR)	426.4/921.0/930.2	35,543	12,213
20	Economic Development Councils-11 (WA and OR)	426.1/930.2	19,243	11,739
21	Other Organizations (6 organizations)	426.1/908.0/930.2	8,312	4,184
22	Total contributions to Commercial and Trade Organizations		101,098	37,621
23	(e) Other Organizations & Donations			
24	MDU Resources expenses (Bismark, ND)	426.1/426.4/921.0	29,750	7,426
25	Grandridge Business Park (Kennewick WA)	930.2	7,414	1,851
26	Other Organizations (6 organizations)	426.1/921.0/930.2	7,011	931
27	Total Other Organizations		44,175	10,208
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
	TOTAL		557,002	158,028

NAME OF RESPONDENT	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION			Dec. 31, 2017

STATE OF OREGON - OFFICERS' SALARIES

- 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.
- 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.
- 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)	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-W Region & Bus Development 3/	Scott W. Madison	4/	
4	VP Operations	Eric P. Martuscelli	4/	
5	VP-Regulatory Affairs & Cust Service 3/	Mark A. Chiles	4/	
6	VP-HR 2/	Anne M. Jones	4/	
7	Assistant Secretary 2/	Julie A. Krenz	4/	
8	General Counsel and Secretary 2/	Daniel S. Kuntz	4/	
9	Assistant Secretary 2/	Karl A. Liepitz	4/	
10	Treasurer 2/	Jason L. Vollmer	4/	
11	Executive VP -Reg Affairs, Cust Service & Gas Supply/1	Garret Senger	4/	
12	Controller 1/	Tammy J. Nygard	4/	
13	Chief Information Officer 2/	Margaret (Peggy) A. Link	4/	
14				
15	1/ Salary includes amount allocated to CNGC from MDU			
16	2/ Salary includes amount allocated to CNGC from MDUR			
17	3/ Salary includes amount allocated to CNGC from IGC			
18	4/ Confidential salary data included on filed reports with OPUC.			
19				
20				
21				
22				
23				
24				
25				

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2017
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STATE OF OREGON-DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

- 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.
- 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	TRC Enviornmental Corporation	Construction	478,609
2	DAS-Co of Idaho	Construction	236,436
3	Heath Consultants, Inc	Consulting	216,736
4	ABI Services, Inc.	Consulting	211,358
5	Parametrix, Inc.	Consulting	105,093
6	Eugene Water & Electric Board	Construction	88,958
7	Deloitte & Touche	Audit	66,887
8	Jacobs Consultancy, Inc.	Consulting	63,803
9	Snelson Companies, Inc.	Construction	57,493
10	Baker Botts, LLP	Legal	47,502
11	Bend Heating	Construction	35,814
12	Garvey Schubert Barer	Consulting	35,132
13	Northwest Metal Fab & Pipe, Inc.	Construction	32,155
14	Evergreen Financial Services	Collections	26,965
15	Others < \$25,000		489,225
16			
17			
18			
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22			
23			
24			
25			
	TOTAL		2,192,166

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(M,D,Y)	Dec. 31, 2017

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

Oregon Production Statistics (therms)

Gas Produced	
Gas Purchased	<u>285,258,585</u>
Total Receipts	<u>285,258,585</u>

Gas Sales	<u>283,103,765</u>
Gas used by Company	<u>52,286</u>
Gas Delivered to LNG Storage - Net	
Losses & Billing Delay	<u>2,102,534</u>
Total Disbursements	<u>285,258,585</u>

Oregon Revenue by Service Class

Residential	<u>\$ 35,525,211</u>
Commercial & Industrial	<u>\$ 24,369,983</u>
Firm	
Interruptible	
Transportation	<u>\$ 4,114,883</u>
Total	<u>\$ 64,010,077</u>

Gas Sold in Therms (Oregon)

Residential	<u>46,992,332</u>
Commercial & Industrial	<u>40,946,727</u>
Firm	
Interruptible	
Transportation	<u>195,164,706</u>
Total	<u>283,103,765</u>

Average Number of Customers

Residential	<u>61,798</u>
Commercial & Industrial	<u>10,099</u>
Firm	
Interruptible	
Transportation	<u>36</u>
Total	<u>71,933</u>

Name of Respondent		This Report Is:		Date of Report	Year/Period of Report
Cascade Natural Gas Corporation		(1)An Original	(2)A Resubmission	(Mo. Da. Yr)	End of Dec. 31, 2017
Distribution of Salaries and Wages Oregon Jurisdiction					
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 Terminating and Processing				
32	Transmission				
33	Distribution	3,287,324			3,287,324
34	Customer Accounts	969,091			969,091
35	Customer Service and Informational	13,201			13,201
36	Sales	-			-
37	Administrative and General	1,671,248			1,671,248
38	TOTAL Operation (Total of lines 28 thru 37)	5,940,864	-	-	5,940,864
39	Maintenance				
40	Production - Manufactured Gas				
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminating and Processing				
44	Transmission				
45	Distribution	1,116,126			1,116,126
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	1,116,126	-	-	1,116,126
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.)(II. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)				
53	Storage, LNG Terminating and Processing (Total of II. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	4,403,450			4,403,450
56	Customer Accounts (Total of line 34)	969,091			969,091
57	Customer Service and Informational (Total of line 35)	13,201			13,201
58	Sales (Total of line 36)	-			-
59	Administrative and General (Total of lines 37 and 46)	1,671,248			1,671,248
60	Total Operation and Maintenance (Total of lines 50 thru 59)	7,056,990	-	-	7,056,990
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	7,056,990	-	-	7,056,990
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	1,868,216			1,868,216
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	1,868,216	-	-	1,868,216
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	117,270			117,270
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	117,270	-	-	117,270
75	PTO/Incentive/Severance Pay Liabilities	486,562			486,562
76	TOTAL Other Accounts	486,562	-	-	486,562
77	TOTAL SALARIES AND WAGES	9,529,038	-	-	9,529,038