e-FILING REPORT COVER SHEET

COMPANY NAME: Cascade Natural Gas Corporation

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

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

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

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

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

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

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

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

THIS FILING IS		
Item 1: [X] 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 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Cascade Natural Gas Corporation	End of 2019/Q4

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information form natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

(a) Submit Forms 2, 2-A and 3-Q electronically through the submission software at http://www.ferc.gov/docs-filing/eforms/form-2/elec-subm-soft.asp .

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

Secretary of the Commission
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

(i) Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 158.10-158.12 for specific qualifications.)

Reference	Reference Schedules Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

Filers should state in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist
.

(e) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders" and "CPA Certification Statement," have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission website at http://www.ferc.gov/help/how-to.asp

(f) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: http://www.ferc.gov/docs-filing/eforms/form-2/form-2.pdf and http://www.ferc.gov/docs-filing/eforms/form-2a/form-2a.pdf, respectively. Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

(a) FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)

(b) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and

(c) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,623 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 250 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 167 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or Dth) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions**.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Footnote and further explain accounts or pages as necessary.

IX. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

X. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

DEFINITIONS	
I.	Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).
II.	Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
III.	Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.
IV	Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW
(Natural Gas Act, 15 U.S.C. 717-717w)

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this act; and may prescribe the form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. § 717t-1(a).

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QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES
IDENTIFICATION

01 Exact Legal Name of Respondent Cascade Natural Gas Corporation	Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change (If name changed during year)	
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 8113 West Grandridge Boulevard, Kennewick, WA 99336-7166	
05 Name of Contact Person 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) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 12/31/2019

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 Kevin Conwell	14 Date Signed 04/15/2020

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

List of Schedules (Natural Gas Company)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

List of Schedules (Natural Gas Company) (continued)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

General Information

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

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) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Control Over Respondent

1. Report in column (a) the names of all corporations, partnerships, business trusts, and similar organizations that directly, indirectly, or jointly held control (see page 103 for definition of control) over the respondent at the end of the year. If control is in a holding company organization, report in a footnote the chain of organization.
2. If control is held by trustees, state in a footnote the names of trustees, the names of beneficiaries for whom the trust is maintained, and the purpose of the trust.
3. In column (b) designate type of control over the respondent. Report an "M" if the company is the main parent or controlling company having ultimate control over the respondent. Otherwise, report a "D" for direct, an "I" for indirect, or a "J" for joint control.

Line No.	Company Name (a)	Type of Control (b)	State of Incorporation (c)	Percent Voting Stock Owned (d)
1	MDU Resources Group, Inc. (MDUR)	M	DE	100.00
2	MDU Energy 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

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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)
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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

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy.	3. Give the date and place of such meeting:
	Total: By Proxy:	

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) _ A Resubmission	12/31/2019	2019/Q4

Important Changes During the Quarter/Year

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service.
Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None
2. None
3. None
4. None
5. None
6. None
7. None
8. Wages for union employees increased by 3.00% in April 2019.
9. None
10. None
11. None
12. None
13. None

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[Next page is 110]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	1,148,216,102	1,077,226,744
3	Construction Work in Progress (107)	200-201	31,106,072	12,854,207
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	1,179,322,174	1,090,080,951
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		508,329,146	490,730,756
6	Net Utility Plant (Total of line 4 less 5)		670,993,028	599,350,195
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)		670,993,028	599,350,195
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)		197,964	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	11,991,542	12,371,315
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)		12,189,506	12,573,345
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		6,896,977	3,203,159
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		0	1,150
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		15,555,347	10,776,951
38	Other Accounts Receivable (143)		5,086,879	13,165,937
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		513,355	460,922
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		140,108	129,531
42	Fuel Stock (151)		0	0
43	Fuel Stock Expenses Undistributed (152)		0	0

Comparative Balance Sheet (Assets and Other Debits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		6,476,402	5,694,283
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	893,659	396,659
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	1,844,137	1,940,549
54	Prepayments (165)	230	5,502,645	4,497,288
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)		32,004,471	25,164,950
59	Miscellaneous Current and Accrued Assets (174)		0	0
60	Derivative Instrument Assets (175)		138,098	0
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
62	Derivative Instrument Assets - Hedges (176)		0	0
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		74,025,368	64,509,535
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		2,122,842	1,624,524
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	48,264,135	56,168,845
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		108,101	0
72	Clearing Accounts (184)		45,130	59,785
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	85,211,361	79,056,464
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)		703,330	744,300
78	Accumulated Deferred Income Taxes (190)	234-235	8,151,888	17,102,003
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		144,606,787	154,755,921
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		901,814,689	831,188,996

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	266,117,553	222,117,553
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	40,331,710	34,416,894
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	2,075,442	2,318,457
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		308,525,705	258,853,904
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	353,814,000	268,211,000
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)		353,814,000	268,211,000
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)		10,454,118	13,232,381
29	Accumulated Provision for Pensions and Benefits (228.3)		6,107,472	5,811,780
30	Accumulated Miscellaneous Operating Provisions (228.4)		24,135	24,135
31	Accumulated Provision for Rate Refunds (229)		0	1,558,020

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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)		74,293,817	66,788,046
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		90,879,542	87,414,362
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		0	0
39	Accounts Payable (232)		44,250,029	66,439,118
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		2,644,766	2,007,577
42	Customer Deposits (235)		783,319	893,105
43	Taxes Accrued (236)	262-263	8,825,425	7,285,166
44	Interest Accrued (237)		3,373,380	3,155,341
45	Dividends Declared (238)		2,480,000	2,960,000
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		314	1,309
49	Miscellaneous Current and Accrued Liabilities (242)	268	9,592,836	8,958,797
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)		71,950,069	91,700,413
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,195,587	4,315,901
58	Accumulated Deferred Investment Tax Credits (255)		201,910	243,929
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	(81,595,224)	(31,014,246)
61	Other Regulatory Liabilities (254)	278	58,505,890	62,967,793
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)		57,867,450	53,594,339
65	Accumulated Deferred Income Taxes - Other (283)		37,469,760	34,901,601
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		76,645,373	125,009,317
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		901,814,689	831,188,996

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Statement of Income

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting mehods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Gas Operating Revenues (400)	300-301	314,395,576	286,825,673	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	216,441,948	192,939,765	0	0
5	Maintenance Expenses (402)	317-325	8,302,734	8,005,146	0	0
6	Depreciation Expense (403)	336-338	29,230,448	26,303,413	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	3,457,659	3,486,360	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	30,542,472	28,430,305	0	0
15	Income Taxes-Federal (409.1)	262-263	(11,525,498)	(5,420,218)	0	0
16	Income Taxes-Other (409.1)	262-263	(941,388)	(461,582)	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	45,039,725	17,131,551	0	0
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	33,563,613	10,752,441	0	0
19	Investment Tax Credit Adjustment-Net (411.4)		(42,019)	(42,184)	0	0
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0	0	0
21	Losses from Disposition of Utility Plant (411.7)		0	0	0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0	0	0
23	Losses from Disposition of Allowances (411.9)		0	0	0	0
24	Accretion Expense (411.10)		0	0	0	0
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		286,942,468	259,620,115	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		27,453,108	27,205,558	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Statement of Income

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	0	0	314,395,576	286,825,673	0	0
3						
4	0	0	216,441,948	192,939,765	0	0
5	0	0	8,302,734	8,005,146	0	0
6	0	0	29,230,448	26,303,413	0	0
7	0	0	0	0	0	0
8	0	0	3,457,659	3,486,360	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	30,542,472	28,430,305	0	0
15	0	0	(11,525,498)	(5,420,218)	0	0
16	0	0	(941,388)	(461,582)	0	0
17	0	0	45,039,725	17,131,551	0	0
18	0	0	33,563,613	10,752,441	0	0
19	0	0	(42,019)	(42,184)	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	0	0	0
25	0	0	286,942,468	259,620,115	0	0
26	0	0	27,453,108	27,205,558	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Statement of Income(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		27,453,108	27,205,558	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)		8,174	8,687	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)		5,013,882	513,668	0	0
38	Allowance for Other Funds Used During Construction (419.1)		(105)	47,519	0	0
39	Miscellaneous Nonoperating Income (421)		4,734	25,876	0	0
40	Gain on Disposition of Property (421.1)		934	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		5,027,619	595,750	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	251,619	147,336	0	0
46	Life Insurance (426.2)		(783,273)	452,957	0	0
47	Penalties (426.3)		94	51	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		306,254	165,577	0	0
49	Other Deductions (426.5)		1,556	615,677	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	(223,750)	1,381,598	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	1,072	1,145	0	0
53	Income Taxes-Federal (409.2)	262-263	587,143	(244,676)	0	0
54	Income Taxes-Other (409.2)	262-263	(89,093)	(27,118)	0	0
55	Provision for Deferred Income Taxes (410.2)	234-235	762,822	152,659	0	0
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	59,042	114,241	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)		1,202,902	(232,231)	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,048,467	(553,617)	0	0
61	**INTEREST CHARGES**					
62	Interest on Long-Term Debt (427)		14,202,081	11,687,433	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	216,975	200,173	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	1,362,795	359,840	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		649,294	291,153	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		15,173,528	11,997,264	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		16,328,047	14,654,677	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)		16,328,047	14,654,677	0	0

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

STATEMENT OF INCOME (continued)

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
27	-	-	27,453,108	27,205,558	-	-
28						
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	8,174	8,687	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	5,013,882	513,668	-	-
38	-	-	(105)	47,519	-	-
39	-	-	4,734	25,876	-	-
40	-	-	934	-	-	-
41	-	-	5,027,619	595,750	-	-
42						
43			-	-		
44			-	-		
45			251,619	147,336		
46			(783,273)	452,957		
47			94	51		
48			306,254	165,577		
49	-	-	1,556	615,677	-	-
50	-	-	(223,750)	1,381,598	-	-
51						
52			1,072	1,145		
53	-	-	587,143	(244,676)	-	-
54	-	-	(89,093)	(27,118)	-	-
55	-	-	762,822	152,659	-	-
56	-	-	(59,042)	(114,241)	-	-
57	-	-	-	-	-	-
58	-	-	-	-	-	-
59	-	-	1,202,902	(232,231)	-	-
60	-	-	4,048,467	(553,617)	-	-
61						
62	-	-	14,202,081	11,687,433	-	-
63	-	-	216,975	200,173	-	-
64	-	-	40,971	40,971	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	1,362,795	359,840	-	-
69	-	-	(649,294)	(291,153)	-	-
70	-	-	15,173,528	11,997,264	-	-
71	-	-	16,328,047	14,654,677	-	-
72						
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	16,328,047	14,654,677	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liabililty Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		2,318,457		
4	Total (lines 2 and 3)		2,318,457		
5	Balance of Account 219 at End of Preceding Quarter/Year		2,318,457		
6	Balance of Account 219 at Beginning of Current Year		2,318,457		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(243,015)		
9	Total (lines 7 and 8)		(243,015)		
10	Balance of Account 219 at End of Current Quarter/Year		2,075,442		

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			2,318,457		
4			2,318,457	14,654,677	16,973,134
5			2,318,457		
6			2,318,457		
7					
8			(243,015)		
9			(243,015)	16,328,047	16,085,032
10			2,075,442		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Statement of Retained Earnings

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		34,416,894	30,688,673
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)			(273,680)
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		16,328,047	14,654,677
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)		10,413,231	10,652,776
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)		40,331,710	34,416,894
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		40,331,710	34,416,894
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
26	Balance-End of Year			

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[Next page is 120]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Statement of Cash Flows

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 116)	16,328,047	14,654,677
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	32,688,107	29,789,773
5	Amortization of (Specify) (footnote details): Gas cost changes	(47,723,076)	(31,058,841)
6	Deferred Income Taxes (Net)	12,179,891	6,417,528
7	Investment Tax Credit Adjustments (Net)	(42,019)	(42,184)
8	Net (Increase) Decrease in Receivables	(4,164,376)	(4,695,510)
9	Net (Increase) Decrease in Inventory	(400,589)	481,096
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	(12,162,567)	26,100,059
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	(4,561,866)	(9,240,144)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	(7,858,448)	32,406,454
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(104,533,294)	(86,201,261)
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	(105)	47,519
27	Other (footnote details): Net increase in customer advances for construction	(120,314)	(171,617)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(104,653,503)	(86,420,397)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	(1,906,236)	67,301
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	(934)	
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	104,082	(672,266)
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(106,456,591)	(87,025,362)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	85,034,707	36,550,000
54	Preferred Stock		
55	Common Stock	44,000,000	30,000,000
56	Other (footnote details):		(37,702)
57	Net Increase in Short-term Debt (c)		
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	129,034,707	66,512,298
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(147,000)	(70,000)
63	Preferred Stock		
64	Common Stock		(397,761)
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(10,880,000)	(10,950,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	118,007,707	55,094,537
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	3,692,668	475,629
75			
76	Cash and Cash Equivalents at Beginning of Period	3,204,309	2,728,680
77			
78	Cash and Cash Equivalents at End of Period	6,896,977	3,204,309

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, 2019 and 2018

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
ASU	FASB Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota (50 percent ownership)
Cascade	Cascade Natural Gas Corporation, a direct wholly owned subsidiary of PCEH
Company	MDU Energy Capital, LLC, a direct wholly owned subsidiary of MDU
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
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
Great Plains	Great Plains Natural Gas Co., a public utility division of Montana-Dakota
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, MDU and MDUR Newco Sub, which resulted in MDU becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota
Intermountain	Intermountain Gas Company, a direct wholly owned subsidiary of PIEH
IPUC	Idaho Public Utilities Commission
MDU	MDU Resources Group, Inc.
MISO	Midcontinent Independent System Operator, Inc.
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a direct wholly owned subsidiary of the Company
MTPSC	Montana Public Service Commission

MW	Megawatt
NDPSC	North Dakota Public Service Commission
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
SDPUC	South Dakota Public Utilities Commission
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
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2019 and 2018

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 the following regulated businesses: Montana-Dakota, and its division Great Plains, PCEH, and its wholly owned subsidiary Cascade, and PIEH, and its wholly owned subsidiary Intermountain. On January 2, 2019, MDU announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company.

The Company's natural gas distribution operations sell natural gas at retail and provide natural gas transportation services. Montana-Dakota's electric operation generates, transmits, and distributes electricity. The Company provides service to approximately 143,000 electric and 978,000 residential, commercial and industrial gas customers in 458 communities. The Montana-Dakota service territory consists of towns in Montana, North Dakota, South Dakota, and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. 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. Montana-Dakota is subject to regulation by the FERC, NDPSC, MTPSC, SDPUC, and WYPSC. Great Plains is subject to regulation by the MNPUC and the NDPSC. 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 for the natural gas operations and during the summer season for the electric operation. Consumption is also influenced by the energy efficiency of customers' appliances, as well as consumer decisions to reduce natural gas and electric usage in response to higher prices.

The consolidated financial statements and disclosures of the Company are presented in accordance with GAAP. Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions that fall under regulatory accounting in accordance with GAAP. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric transmission and generating facilities. The accounting policies followed by the Company's subsidiaries are generally subject to the Uniform System of Accounts of the FERC.

The Company's subsidiaries 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 5 for more information regarding the nature and amounts of these regulatory deferrals.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the

Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued, and the FASB adopted, rules that allowed 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. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Effective January 1, 2019, the Company early adopted the requirements of the ASU on leases, as further discussed in this note, as well as in Note 3. As such, results for reporting periods beginning January 1, 2019, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with the historic accounting for leases.

Management has also evaluated the impact of events occurring after December 31, 2019, up to the date of the issuance of these consolidated financial statements on March 30, 2020, that would require recognition or disclosure in the financial statements.

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

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts. The total balance of receivables past due 90 days or more was $1.6 million and $1.2 million as of December 31, 2019 and 2018, 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, 2019 and 2018 was $1.4 million and $1.5 million, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at the Company was $100.8 million and $96.2 million at December 31, 2019 and 2018, respectively.

Inventories and natural gas in storage
Natural gas in storage is valued at lower of cost or market using the last-in, first-out method at Montana-Dakota and Great Plains; and, the lower of cost or net realizable value using the first-in, first-out method at Cascade and the average cost method at Intermountain. The majority of other inventories are valued at lower of cost or net realizable value using the average cost method. The portion of the cost of natural gas in storage expected to be used within 12 months was included in inventories. Inventories at December 31 consisted of:

		2019		2018
		(In thousands)		
Natural gas in storage (current)	**$**	**17,019**	$	16,112
Other		**4,559**		4,785
Total	**$**	**21,578**	$	20,897

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 $1.6 million and $1.7 million at December 31, 2019 and 2018, respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies, an insurance contract, and other miscellaneous investments. 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 other investments. For more information, see Notes 6 and 11.

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 for the years ended December 31 were as follows:

		2019		2018
		(In thousands)		
AFUDC - borrowed	**$**	**2,535**	$	1,943
AFUDC - equity	**$**	**669**	$	1,074

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. These amounts are recorded as regulatory liabilities, which are included in deferred credits and other liabilities - other.

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

	2019	2018	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Electric:			
Generation	**$ 1,139,059**	$ 1,131,484	48
Distribution	**443,780**	430,750	46
Transmission	**445,485**	302,315	65
Construction in progress	**66,664**	161,893	-
Other	**132,157**	122,127	15
Natural Gas:			
Distribution	**$ 2,133,249**	$ 1,981,356	47
Transmission	**104,401**	104,518	52
Storage	**31,484**	29,111	24
General	**191,446**	186,478	14
Other	**188,037**	176,601	14
Construction in progress	**39,506**	21,028	-
Less: accumulated depreciation and amortization	**1,552,325**	1,450,961	
Net property, plant and equipment	**$ 3,362,943**	$ 3,196,700	

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 2019 and 2018. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Leases
Lease liabilities and their corresponding right-of-use assets are recorded based on the present value of lease payments over the expected lease term. The Company recognizes leases with an original lease term of 12 months or less in income on a straight-line basis over the term of the lease and does not recognize a corresponding right-of-use asset or lease liability. The Company determines the lease term based on the non-cancelable and cancelable periods in each contract. The non-cancelable period consists of the term of the contract that is legally enforceable and cannot be canceled by either party without incurring a significant

penalty. The cancelable period is determined by various factors that are based on who has the right to cancel a contract. If only the lessor has the right to cancel the contract, the Company will assume the contract will continue. If the lessee is the only party that has the right to cancel the contract, the Company looks to asset, entity and market-based factors. If both the lessor and the lessee have the right to cancel the contract, the Company assumes the contract will not continue.

The discount rate used to calculate the present value of the lease liabilities is based upon the implied rate within each contract. If the rate is unknown or cannot be determined, the Company uses an incremental borrowing rate, which is determined by the length of the contract, asset class and the Company's borrowing rates, as of the commencement date of the contract.

Regulatory assets and liabilities

The Company accounts for certain income and expense items under the provisions of regulatory accounting, which requires the Company to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income. The Company records regulatory assets or liabilities at the time the Company determines the amounts to be recoverable in current or future rates.

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 the Company completes in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. 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.

Goodwill impairment, if any, is measured by 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 goodwill of the reporting unit is not impaired. If the carrying value of a reporting unit exceeds its fair value, the Company must record an impairment loss for the amount that the carrying value of the reporting unit, including goodwill, exceeds the fair value of the reporting unit. For the years ended December 31, 2019 and 2018, there were no impairment losses recorded. At December 31, 2019, the fair value substantially exceeded the carrying value of its 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, risk adjusted capital cost, 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 risk adjusted capital cost at each reporting unit. Risk adjusted capital cost of 4.0 percent, and a long-term growth rate projection of 1.7 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2019. Under the market approach, the Company estimates fair value using various multiples derived from 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 a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The Company generates revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. The Company establishes a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Company’s utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable state’s tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the Company has no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered.

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 regulatory asset or liability.

Legal costs
The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 36 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $23.8 million and $30.0 million at December 31, 2019 and 2018, respectively. Natural gas costs recoverable through rate adjustments were $89.2 million and $42.7 million at December 31, 2019 and 2018, respectively.

Income taxes

MDU and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Pursuant to the tax sharing agreement that exists between MDU and its subsidiaries, 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. 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 liabilities are expected to be reflected as a reduction in future rates charged to customers 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 recognizes 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 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.

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; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; regulatory assets expected to be recovered in rates charged to customers; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; lease classification; present value of right-of-use assets and lease liabilities; 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
ASU 2016-02 - Leases In February 2016, the FASB issued this ASU guidance relating to ASC 842 - *Leases*. The guidance required lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remained 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 required additional disclosures, both quantitative and qualitative, related to operating and financing leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company early adopted the standard on January 1, 2019.

In July 2018, the FASB issued ASU 2018-11 - *Leases: Targeted Improvements*, an accounting standard update to ASU 2016-02. This ASU provided an entity the option to adopt the guidance using one of two modified retrospective approaches. An entity could adopt the guidance using the modified retrospective transition approach beginning in the earliest year presented in the financial statements. This method of adoption would have required the restatement of prior periods reported and the presentation of lease disclosures under the new guidance for all periods reported. The additional transition method of adoption, introduced by ASU 2018-11, allowed entities the option to apply the guidance on the date of adoption by recognizing a cumulative effect adjustment to retained earnings during the period of adoption and did not require prior comparative periods to be restated.

The Company early adopted the standard on January 1, 2019, utilizing the additional transition method of adoption applied on the date of adoption and the practical expedient that allowed the Company to not reassess whether an expired or existing contract contained a lease, the classification of leases or initial direct costs. The Company did not identify any cumulative effect adjustments. The Company also adopted a short-term leasing policy as the lessee where leases with a term of 12 months or less are not included on the Consolidated Balance Sheet.

As a practical expedient, a lessee may choose not to separate nonlease components from lease components and instead account for lease and nonlease components as a single lease component. The election shall be made by asset class. The Company has elected to adopt the lease/nonlease component practical expedient for all asset classes as the lessee. The Company did not elect the practical expedient to use hindsight when assessing the lease term or impairment of right-of-use assets for the existing leases on the date of adoption. 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 has adopted this practical expedient.

The Company formed a lease implementation team to review and assess existing contracts to identify and evaluate those containing leases. Additionally, the team implemented new and revised existing software to meet the reporting and disclosure requirements of the standard. The Company also assessed the impact the standard had on its processes and internal controls and identified new and updated existing internal controls and processes to ensure compliance with the new lease standard; such modifications were not deemed to be significant. During the assessment phase, the Company used various surveys, reconciliations and analytic methodologies to ensure the completeness of the lease inventory. The Company determined that most of the current operating leases were subject to the guidance and were recognized as operating lease liabilities and right-of-use assets on the Consolidated Balance Sheet upon adoption. On January 1, 2019, the Company recorded $20.7 million to right-of-use assets and lease liabilities as a result of the initial adoption of the guidance. In addition, the Company evaluated the impact the new guidance had on lease contracts where the Company is the lessor and determined it did not have a significant impact to the Company's financial statements.

ASU 2017-04 - 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 Company early adopted the guidance on a prospective basis beginning with the preparation of its 2019 goodwill impairment test in the fourth quarter of 2019. The adoption of the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures.

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August 2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The Company early adopted the guidance on January 1, 2019, on a prospective basis. The adoption of the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures.

Recently issued accounting standards not yet adopted

ASU 2016-13 - Measurement of Credit Losses on Financial Instruments In June 2016, the FASB issued guidance on the measurement of credit losses on certain financial instruments. The guidance introduces a new impairment model known as the current expected credit loss model that will replace the incurred loss impairment methodology currently included under GAAP. This guidance requires entities to present certain investments in debt securities, trade accounts receivable and other financial assets at their net carrying value of the amount expected to be collected on the financial statements. The Company early adopted the guidance on January 1, 2020.

The Company formed an implementation team to review and assess existing financial assets to identify and evaluate the financial assets subject to the new current expected credit loss model. The Company assessed the impact of the guidance on its processes and internal controls and has identified and updated existing internal controls and processes to ensure compliance with the new guidance; such modifications were deemed insignificant. During the assessment phase, the Company completed checklists to identify the complete portfolio of assets subject to the current expected credit loss model. The Company determined the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures and did not record a material cumulative effect adjustment upon adoption.

ASU 2018-13 - Changes to the Disclosure Requirements for Fair Value Measurement In August 2018, the FASB issued guidance on modifying the disclosure requirements on fair value measurements as part of the disclosure framework project. The guidance modifies, among other things, the disclosures required for Level 3 fair value measurements, including the range and weighted average of significant unobservable inputs. The guidance removes, among other things, the disclosure requirement to disclose transfers between Levels 1 and 2. The guidance will be effective for the Company on January 1, 2020, with early adoption permitted. Level 3 fair value measurement disclosures should be applied prospectively while all other amendments should be applied retrospectively. The Company continues to evaluate the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-14 - Changes to the Disclosure Requirements for Defined Benefit Plans In August 2018, the FASB issued guidance on modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans as part of the disclosure framework project. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The guidance adds, among other things, the requirement to include an explanation for significant gains and losses related to changes in benefit obligations for the period. The guidance removes, among other things, the disclosure requirement to disclose the amount of net periodic benefit costs to be amortized over the next fiscal year from accumulated other comprehensive income (loss) and the effects a one percentage point change in assumed health care cost trend rates will have on certain benefit components. The guidance will be effective for the Company on January 1, 2022, and must be applied on a retrospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2019-12 - Simplifying the Accounting for Income Taxes In December 2019, the FASB issued guidance on simplifying the accounting for income taxes by removing certain exceptions in ASC 740 and providing simplification amendments. The guidance removes exceptions on intraperiod tax allocations and reporting and provides simplification on accounting for franchise taxes, tax basis goodwill and tax law changes. The guidance will be effective for the Company on January 1, 2022, with early adoption permitted. Transition requirements vary among the exceptions and amendments which include retrospective, modified retrospective and prospective application. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

Variable interest entities

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

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

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

Accumulated other comprehensive income (loss)

The Company’s accumulated other comprehensive income (loss) is comprised of postretirement liability adjustments.

The postretirement liability adjustment in other comprehensive loss was $7.0 million, net of tax of $2.4 million, for the year ended December 31, 2019.

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

	Postretirement Liability Adjustment	Total Accumulated Other Comprehensive Loss
	(In thousands)	
At December 31, 2017	$ (5,946)	$ (5,946)
Other comprehensive income before reclassifications	903	903
Amounts reclassified from accumulated other comprehensive loss	1,320	1,320
Net current-period other comprehensive income	2,223	2,223
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(1,291)	(1,291)
At December 31, 2018	$ (5,014)	$ (5,014)
Other comprehensive loss before reclassifications	(2,396)	(2,396)
Amounts reclassified from accumulated other comprehensive loss	448	448
Net current-period other comprehensive loss	(1,948)	(1,948)
At December 31, 2019	**$ (6,962)**	**$ (6,962)**

NOTE 2 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

As part of the adoption of ASC 606 - *Revenue from Contracts with Customers,* the Company elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is 12 months or less.

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by business lines.

Year Ended December 31, 2019	Electric	Natural Gas Distribution	Total
		(In thousands)	
Residential utility sales	$ 125,369	$ 483,452	$ 608,821
Commercial utility sales	141,596	296,835	438,431
Industrial utility sales	37,765	26,895	64,660
Other utility sales	7,408	---	7,408
Natural gas transportation	---	45,449	45,449
Other	35,574	12,726	48,300
Revenues from contracts with customers	347,712	865,357	1,213,069
Revenues out of scope	4,013	(135)	3,878
Total external operating revenues	$ 351,725	$ 865,222	$ 1,216,947

Year Ended December 31, 2018	Electric	Natural Gas Distribution	Total
		(In thousands)	
Residential utility sales	$ 121,477	$ 457,959	$ 579,436
Commercial utility sales	136,236	276,716	412,952
Industrial utility sales	34,353	24,603	58,956
Other utility sales	7,556	---	7,556
Natural gas transportation	---	43,238	43,238
Other	31,568	14,579	46,147
Revenues from contracts with customers	331,190	817,095	1,148,285
Revenues out of scope	3,933	6,152	10,085
Total external operating revenues	$ 335,123	$ 823,247	$ 1,158,370

NOTE 3 – LEASES

Most of the leases the Company enters into are for equipment, buildings and easements as part of their ongoing operations. The Company also leases certain equipment to third parties. The Company determines if an arrangement contains a lease at inception of a contract and accounts for all leases in accordance with ASC 842 - *Leases*. For more information on the adoption of ASC 842, see Note 1.

The recognition of leases requires the Company to make estimates and assumptions that affect the lease classification and the assets and liabilities recorded. The accuracy of lease assets and liabilities reported on the Consolidated Financial Statements depends on, among other things, management's estimates of interest rates used to discount the lease assets and liabilities to their present value, as well as the lease terms based on the unique facts and circumstances of each lease.

Lessee accounting

The leases the Company has entered into as part of its ongoing operations are considered operating leases and are recognized on the Consolidated Balance Sheets as right-of-use assets, current lease liabilities and, if applicable, noncurrent lease liabilities. The corresponding lease costs are included in operation and maintenance expense on the Consolidated Statements of Income.

Generally, the leases for equipment have a term of five years or less and buildings and easements have a longer term of up to 35 years or more. To date, the Company does not have any residual value guarantee amounts probable of being owed to a lessor, financing leases or material agreements with related parties.

The following tables provide information on the Company's operating leases at and for the year ended December 31, 2019:

	(In thousands)	
Lease costs:		
Operating lease cost	$	1,937
Variable lease cost		383
Short-term lease cost		72
Total lease costs	$	2,392

	(Dollars in thousands)	
Weighted average remaining lease term		23.94 years
Weighted average discount rate		4.65%
Cash paid for amounts included in the measurement of lease liabilities	$	1,937

The reconciliation of the future undiscounted cash flows to the operating lease liabilities presented on the Consolidated Balance Sheet at December 31, 2019, was as follows:

	(In thousands)	
2020	$	1,884
2021		1,758
2022		1,473
2023		1,396
2024		1,360
Thereafter		26,259
Total		34,130
Less discount		14,079
Total operating lease liabilities	$	20,051

The undiscounted annual minimum lease payments due under the Company's leases following the previous lease accounting standard as of December 31, 2018, were as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Operating leases	$ 1,702	$ 1,638	$ 1,569	$ 1,371	$ 1,338	$ 27,122

Lessor accounting
The Company leases certain equipment to third parties, which are considered operating leases. The Company recognized revenue from operating leases of $381,000 for the year ended December 31, 2019.

The majority of the Company's operating leases are short-term leases of less than 12 months. At December 31, 2019, the Company had $3,000 of lease receivables with a majority due within 12 months or less.

NOTE 4 – GOODWILL
The carrying amount of goodwill for the years ended December 31, 2019 and 2018 remained unchanged at $345.7 million. No impairments of goodwill have been recorded.

NOTE 5 – REGULATORY ASSETS AND LIABILITIES
The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period *	**2019**	2018
			(In thousands)
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	**$ 136,341**	$ 145,549
Natural gas costs recoverable through rate adjustments	Up to 3 years	**89,204**	42,653
Plants to be retired (a)	-	**32,931**	-
Cost recovery mechanisms (a) (b)	Up to 3 years	**19,396**	18,122
Asset retirement obligations (a)	Over plant lives	**17,317**	13,763
Manufactured gas plant sites remediation (a)	-	**15,347**	17,068
Taxes recoverable from customers (a)	Over plant lives	**10,232**	10,663
Conservation programs (a) (b)	Up to 3 years	**7,405**	7,007
Long-term debt refinancing costs (a)	Up to 18 years	**4,286**	4,898
Costs related to identifying generation development (a)	Up to 7 years	**2,052**	2,508
Other (a) (b)	Up to 19 years	**9,925**	9,624
Total regulatory assets		**344,436**	271,855
Regulatory liabilities:			
Taxes refundable to customers (c) (d)		**214,202**	241,454
Plant removal and decommissioning costs (c)		**166,730**	166,849
Natural gas costs refundable through rate adjustments (d)		**23,825**	29,995
Pension and postretirement benefits (c)		**14,446**	10,309
Other (c) (d)		**25,150**	24,680
Total regulatory liabilities		**444,353**	473,287
Net regulatory position		**$(99,917)**	$(201,432)

* *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.

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, 2019 and 2018, approximately $203.5 million and $245.2 million, respectively, of regulatory assets were not earning a rate of return.

During the first quarter of 2019 and the fourth quarter of 2018, the Company experienced increased natural gas costs in certain jurisdictions where it supplies natural gas. The Company has recorded these natural gas costs as regulatory assets as they are expected to be recovered from customers, as discussed in Note 13.

In February 2019, the Company announced that it intends to retire three aging coal-fired electric generating units in early 2021 and early 2022. The Company has accelerated the depreciation related to these facilities in property, plant and equipment and has recorded the difference between the accelerated depreciation, in accordance with GAAP, and the depreciation approved for rate-making purposes as regulatory assets. The Company expects to recover the regulatory assets related to the plants to be retired in future rates.

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 6 – FAIR VALUE MEASUREMENTS

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified defined 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 $26.7 million and $22.7 million as of December 31, 2019 and 2018, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized gains (losses) on these investments for the years ended December 31, 2019 and 2018, were $4.0 million and ($1.1 million), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in other income 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 fair value 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.

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, 2019 and 2018, 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, 2019, 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, 2019
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 1,635	$---	$ 1,635
Insurance contract*	---	26,697	---	26,697
Total assets measured at fair value	$ ---	$ 28,332	$---	$ 28,332

** The insurance contract invests approximately 51 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 12 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 percent in target date investments and 1 percent in cash equivalents.*

	Fair Value Measurements at December 31, 2018, 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, 2018
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 4,559	$---	$ 4,559
Insurance contract*	---	22,656	---	22,656
Total assets measured at fair value	$ ---	$ 27,215	$---	$ 27,215

** The insurance contract invests approximately 53 percent in fixed-income investments, 21 percent in common stock of large-cap companies, 11 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 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.

In the second quarter of 2019, the Company reviewed a non-utility investment for impairment. This was a cost-method investment and was written down to zero using the income approach to determine its fair value, requiring the Company to record a write-down of $2.0 million, before tax. The fair value of this investment was categorized as Level 3 in the fair value hierarchy. The reduction is reflected in investments on the Consolidated Balance Sheet, as well as within other income on the Consolidated Statement of Income.

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 categorized as Level 2 in the fair value hierarchy and 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:

	2019		2018	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,526,048**	**$ 1,671,171**	$ 1,353,981	$ 1,424,909

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

NOTE 7 – DEBT

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive and financial covenants and cross-default provisions. In order to borrow under the debt agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company were in compliance with at December 31, 2019. 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's subsidiaries:

Company	Facility		Facility Limit	Amount Outstanding at December 31, 2019	Amount Outstanding at December 31, 2018	Letters of Credit at December 31, 2019	Expiration Date
				(in millions)			
Montana-Dakota Utilities Co.	Commercial Paper/Revolving credit agreement	(a)	$ 175.0	$ 118.6 (b)	$ 48.5	$ ----	12/19/24
Cascade Natural Gas Corporation	Revolving credit agreement		$ 100.0 (c)	$ 64.6	$ 53.8	$ 2.2 (d)	6/7/24
Intermountain Gas Company	Revolving credit agreement		$ 85.0 (e)	$ 24.5	$ 56.3	$ 1.4 (d)	6/7/24

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Montana-Dakota on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the revolving credit agreement at December 31, 2019, and $48.5 million was outstanding at December 31, 2018.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $125.0 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.

Montana-Dakota's commercial paper program is supported by a revolving credit agreement. While the amount of commercial paper outstanding does not reduce available capacity under the revolving credit agreement, Montana-Dakota does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to seasonality of certain operations of the Company's subsidiaries.

The following includes information related to the preceding table.

Long-term debt

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

	Weighted Average Interest Rate at December 31, 2019		2019	2018
			(In thousands)	
Senior Notes due on dates ranging from October 22, 2022 to November 18, 2059	**4.38%**	**$**	**1,240,000**	$ 915,000
Commercial paper supported by revolving credit agreements	**2.03%**		**118,600**	48,500
Term Loan Agreement due on September 3, 2032	**2.00%**		**9,100**	209,800
Credit agreements due on June 7, 2024	**4.40%**		**89,050**	110,100
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 February 1, 2035 to November 30, 2038	**5.26%**		**24,628**	24,786
Less unamortized debt issuance costs			**5,330**	4,205
Total long-term debt			**1,526,048**	1,353,981
Less current maturities			**15,700**	200,711
Net long-term debt		**$**	**1,510,348**	$1,153,270

Montana-Dakota On January 1, 2019, MDU's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same. For more information on the reorganization, see Note 1.

On December 19, 2019, Montana-Dakota amended and restated its revolving credit agreement extending the maturity date to December 19, 2024. Montana-Dakota's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The credit agreement contains customary covenants and provisions, including covenants of Montana-Dakota not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) 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.

On July 24, 2019, Montana-Dakota entered into a $200.0 million note purchase agreement with maturity dates ranging from October 17, 2039 to November 18, 2059, at a weighted average interest rate of 3.95 percent. The agreement contains customary covenants and provisions, including a covenant of Montana-Dakota not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent.

Montana-Dakota's ratio of total debt to total capitalization at December 31, 2019, was 52 percent.

Cascade On June 7, 2019, Cascade amended its revolving credit agreement to increase the borrowing capacity to $100.0 million and extend the maturity date to June 7, 2024. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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

On June 13, 2019, Cascade issued $75.0 million of senior notes with maturity dates ranging from June 13, 2029 to June 13, 2049, at a weighted average interest rate of 3.93 percent. The 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.

Cascade's ratio of total debt to total capitalization at December 31, 2019, was 53 percent.

Intermountain On June 7, 2019, Intermountain amended its revolving credit agreement to extend the maturity date to June 7, 2024. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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

On June 13, 2019, Intermountain issued $50.0 million of senior notes with maturity dates ranging from June 13, 2029 to June 13, 2049, at a weighted average interest rate of 3.92 percent. The 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.

Intermountain's ratio of total debt to total capitalization at December 31, 2019, was 50 percent.

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, 2019, were as follows:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Long-term debt maturities	$15,700	$700	$12,200	$47,200	$268,350	$1,187,228

NOTE 8 – ASSET RETIREMENT OBLIGATIONS

The Company records obligations related to retirement costs of natural gas distribution mains and lines, decommissioning of certain electric generating facilities, 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 for the years ended December 31 was as follows:

	2019	2018
	(In thousands)	
Balance at beginning of year	**$ 296,254**	$ 267,171
Liabilities incurred	**20,916**	12,302
Liabilities settled	**(3,988)**	(2,076)
Accretion expense (largely related to regulatory assets)	**15,894**	14,569
Revisions in estimates	**2,821**	4,288
Balance at end of year	**$ 331,897**	$296,254

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. For more information on the Company's regulatory assets and liabilities, see Note 5.

NOTE 9 – INCOME TAXES

Income before income taxes for the years ended December 31, 2019 and 2018 was $83.0 million and $82.3 million, respectively.

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

	2019	2018
	(In thousands)	
Current:		
Federal	**$ (36,310)**	$ (18,480)
State	**(4,896)**	(656)
	(41,206)	(19,136)
Deferred:		
Income taxes:		
Federal	**24,394**	13,237
State	**4,469**	1,718
Investment tax credit - net	**1,099**	1,774
	29,962	16,729

Total income tax benefit	**$ (11,244)**	$ (2,407)

The Company 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 was deferred under regulatory accounting as the Company worked with the various regulators to determine the amount and timing of amounts to be returned to customers. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers.

The changes included in the TCJA were broad and complex. The SEC issued rules that allowed 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 reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

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

	2019	2018
	(In thousands)	
Deferred tax assets:		
Postretirement	**$ 19,644**	$ 25,541
Customer advances	**7,301**	7,704
Compensation-related	**9,625**	7,553
Federal renewable energy credit	**5,343**	8,015
Other	**9,391**	13,244
Total deferred tax assets	**51,304**	62,057
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**283,263**	270,412
Postretirement	**36,626**	38,547
Purchased gas adjustment	**20,005**	9,574
Other	**23,963**	14,157
Total deferred tax liabilities	**363,857**	332,690
Net deferred income tax liability	**$ (312,553)**	$ (270,633)

As of December 31, 2019 and 2018, no valuation allowance has been recorded associated with the above deferred tax assets. The federal renewable energy credit carryforward expires in 2040 if not utilized. Changes in tax regulations or assumptions regarding current and future taxable income could require a valuation allowance in the future.

The following table reconciles the change in the net deferred income tax liability from December 31, 2018, to December 31, 2019, to deferred income tax expense:

	2019
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 41,920**
Deferred taxes associated with other comprehensive income	**646**
Deferred taxes associated with TCJA enactment	**(11,071)**
Other	**(1,533)**
Deferred income tax expense for the period	**$ 29,962**

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,	**2019**		2018	
	Amount	**%**	Amount	%
		(Dollars in thousands)		
Computed tax at federal statutory rate	**$ 17,437**	**21.0**	$ 17,288	21.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	**231**	**0.3**	1,238	1.5
Excess deferred income tax amortization	**(11,071)**	**(13.3)**	(9,287)	(11.3)
Federal renewable energy tax credits	**(15,843)**	**(19.1)**	(11,759)	(14.3)
Flow-through	**448**	**0.5**	(308)	(0.4)
AFUDC equity	**284**	**0.3**	123	0.1
Amortization of deferral of investment tax credit	**1,037**	**1.2**	1,774	2.2
Resolution of tax matters and uncertain tax positions	**(53)**	**(0.1)**	240	0.3
Other	**(3,714)**	**(4.5)**	(1,716)	(2.0)
Total income tax expense	**$ (11,244)**	**(13.7)**	$ (2,407)	(2.9)

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 2015. With few exceptions, as of December 31, 2019, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2015.

For the years ended December 31, 2019 and 2018, total reserves for uncertain tax positions were not material. The Company recognizes interest and penalties accrued relative to unrecognized tax benefits in income tax expense.

NOTE 10 – CASH FLOW INFORMATION

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

	2019	2018
	(In thousands)	
Interest, net*	**$ 57,025**	$ 55,726
Income taxes paid (refunded), net	**$ (33,654)**	$ (24,740)

* AFUDC - borrowed was $2,535 and $1,943 for the years ended December 31, 2019 and 2018, respectively.

Noncash investing transactions at December 31 were as follows:

	2019	2018
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 31,640**	$ 31,829
Right-of-use assets obtained in exchange for new operating lease liabilities	**$ 20,051**	$ ---

NOTE 11 – 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, all of the Company's defined benefit pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits, to an annuity company. The transfer of the benefit payments for these participants reduced the Company's liability and future premiums.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified. Current employees at Montana-Dakota and 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, were provided the option to choose between a pre-65 comprehensive medical plan coupled with a Medicare supplement or a specified company funded Retiree Reimbursement Account, regardless of when they retire. All other eligible employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire to be eligible for a specified company funded Retiree Reimbursement Account. Employees at Montana-Dakota and 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.

Changes in benefit obligation and plan assets for the years ended December 31, 2019 and 2018, and amounts recognized in the Consolidated Balance Sheets at December 31, 2019 and 2018, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 273,925**	$ 312,802	**$ 49,532**	$ 57,275
Service cost	**---**	---	**530**	694
Interest cost	**10,637**	10,221	**1,830**	1,752
Plan participants' contributions	**---**	---	**855**	1,070
Actuarial (gain) loss	**27,689**	(23,251)	**1,818**	(7,371)
Benefits paid	**(19,293)**	(25,847)	**(3,660)**	(3,888)
Benefit obligation at end of year	**292,958**	273,925	**50,905**	49,532
Change in net plan assets:				
Fair value of plan assets at beginning of year	**218,431**	253,102	**62,056**	68,015
Actual gain (loss) on plan assets	**41,486**	(15,307)	**11,720**	(3,352)
Employer contribution	**15,452**	6,483	**29**	211
Plan participants' contributions	**---**	---	**855**	1,070
Benefits paid	**(19,293)**	(25,847)	**(3,660)**	(3,888)
Fair value of net plan assets at end of year	**256,076**	218,431	**71,000**	62,056
Funded status – over (under)	**$ (36,882)**	$ (55,494)	**$ 20,095**	$ 12,524
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ ---**	$ ---	**$ 20,095**	$ 13,165
Other liabilities (noncurrent)	**(36,882)**	(55,494)	**---**	(641)
Net amount recognized	**$ (36,882)**	$ (55,494)	**$ 20,095**	$ 12,524
Amounts recognized in regulatory assets or liabilities:				
Actuarial (gain) loss	**$ 134,756**	$ 139,589	**$ (2,330)**	$ 4,566
Prior service credit	**---**	---	**(7,104)**	(8,242)
Total	**$ 134,756**	$ 139,589	**$ (9,434)**	$ (3,676)

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 or liabilities are expected to be reflected in rates charged to customers over time. For more information on regulatory assets and liabilities see Note 5.

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:

	2019	2018
	(In thousands)	
Projected benefit obligation	**$ 292,958**	$273,925
Accumulated benefit obligation	**$ 292,958**	$273,925
Fair value of plan assets	**$ 256,076**	$218,431

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	
	2019	2018	**2019**	2018
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 530**	$ 694
Interest cost	**10,637**	10,221	**1,830**	1,752
Expected return on assets	**(13,014)**	(14,810)	**(3,603)**	(3,667)
Amortization of prior service credit	**---**	---	**(1,114)**	(1,111)
Recognized net actuarial loss	**3,879**	4,970	**243**	286
Net periodic benefit cost (credit), including amount capitalized	**1,502**	381	**(2,114)**	(2,046)
Less amount capitalized	**---**	---	**113**	143
Net periodic benefit cost (credit)	**1,502**	381	**(2,227)**	(2,189)
Other changes in plan assets and benefit obligations recognized in regulatory assets or liabilities:				
Net (gain) loss	**(745)**	6,986	**(6,654)**	(696)
Amortization of actuarial loss	**(4,088)**	(4,970)	**(243)**	(286)
Amortization of prior service credit	**---**	---	**1,139**	1,111
Total recognized in regulatory assets or liabilities	**(4,833)**	2,016	**(5,758)**	129
Total recognized in net periodic benefit cost (credit) and regulatory assets or liabilities	**$ (3,331)**	$ 2,397	**$ (7,985)**	$ (2,060)

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets or liabilities into net periodic benefit cost in 2020 is $5.0 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets or liabilities into net periodic benefit credit in 2020 are $66,000 and $1.0 million, respectively. Prior service credit 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	
	2019	2018	**2019**	2018
Discount rate	**2.96%**	4.02%	**2.97%**	4.03%
Expected return on plan assets	**6.25%**	6.75%	**5.75%**	5.75%

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

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
Discount rate	**4.02%**	3.37%	**4.03%**	3.38%
Expected return on plan assets	**6.25%**	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, 2019, 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 of 30 percent equity securities and 70 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

	2019	2018
Health care trend rate assumed for next year	**7.4%**	7.5% - 8.0%
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 Company contributes a flat dollar amount to the monthly premiums, which is updated annually on January 1.

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, 2019:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 79	$ (69)
Effect on postretirement benefit obligation	$ 1,506	$ (1,320)

In 2019, the Company contributed an additional $12.4 million to its defined benefit pension plans, which increased the funded status and decreased future expenses for the plans. The Company does not expect to contribute to its defined benefit pension and postretirement benefit plans in 2020.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2019, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2020	16,885	3,322	64
2021	17,023	3,290	60
2022	17,223	3,265	56
2023	17,355	3,232	50
2024	17,449	3,168	45
2025-2029	84,885	15,074	153

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 fair value 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.

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, 2019 and 2018, 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, 2019, 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, 2019
	(In thousands)			
Assets:				
Cash equivalents	$ ---	$ 18,344	$ ---	$ 18,344
Equity securities:				
U.S. companies	10,135	---	---	10,135
International companies	---	658	---	658
Collective and mutual funds*	112,807	41,289	---	154,096
Corporate bonds	---	56,624	---	56,624
Municipal bonds	---	8,292	---	8,292
U.S. Government securities	5,115	1,460	---	6,575
Total assets measured at fair value	$128,057	$126,667	$ ---	$254,724

* *Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in common stock of large-cap U.S. companies, 18 percent in U.S. Government securities, 9 percent in corporate bonds, 6 percent in cash equivalents and 17 percent in other investments.*

	Fair Value Measurements at December 31, 2018, 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, 2018
		(In thousands)		
Assets:				
Cash equivalents	$ ---	$ 3,498	$ ---	$ 3,498
Equity securities:				
U.S. companies	7,833	---	---	7,833
International companies	---	687	---	687
Collective and mutual funds*	103,578	36,617	---	140,195
Corporate bonds	---	51,881		51,881
Municipal bonds	---	7,539	---	7,539
U.S. Government securities	340	4,184	---	4,524
Total assets measured at fair value	$111,751	$104,406	$ ---	$ 216,157

* *Collective and mutual funds invest approximately 27 percent in common stock of international companies, 31 percent in corporate bonds, 18 percent in common stock of large-cap U.S. companies, 5 percent in cash equivalents and 19 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, 2019 and 2018, 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, 2019, 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, 2019
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 3,015	$ ---	$ 3,015
Equity securities:				
U.S. companies	1,556	---	---	1,556
International companies	---	1	---	1
Insurance contract*	8	66,420	---	66,428
Total assets measured at fair value	$ 1,564	$69,436	$ ---	$ 71,000

** The insurance contract invests approximately 50 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 11 percent in other investments.*

	Fair Value Measurements at December 31, 2018, 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, 2018
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 2,915	$ ---	$ 2,915
Equity securities:				
U.S. companies	1,401	---	---	1,401
International companies	---	2	---	2
Insurance contract*	1	57,737	---	57,738
Total assets measured at fair value	$ 1,402	$60,654	$ ---	$ 62,056

** The insurance contract invests approximately 51 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 12 percent in other investments.*

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified defined benefit plans for executive officers and certain key management employees. Montana-Dakota's plan provides for defined benefit payments following the employee's retirement or, upon death, to their beneficiaries for up to a 15-year period. 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, 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 projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2019	2018
	(In thousands)	
Projected benefit obligation	**$ 30,367**	$ 29,262
Accumulated benefit obligation	**$ 30,367**	$ 29,262

Components of net periodic benefit cost for these plans for the years ended December 31 were as follows:

	2019	2018
	(In thousands)	
Components of net periodic		
Service cost	**$ 109**	$ 185
Interest cost	**1,088**	1,004
Recognized net actuarial loss	**532**	654
Net periodic benefit cost	**$ 1,729**	$ 1,843

Weighted average assumptions used at December 31 were as follows:

	2019	2018
Benefit obligation discount rate	**2.76%**	3.88 %
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.89%**	3.22 %
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

The amount of future benefit payments for the unfunded, nonqualified defined benefit plans at December 31, 2019, are expected to aggregate as follows:

	2020	2021	2022	2023	2024	2025-2029
			(In thousands)			
Nonqualified benefits	$ 2,696	$ 2,649	$ 2,543	$ 2,562	$ 2,468	$ 9,681

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2019 and 2018 were $227,000 and $86,000, respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

	2019	2018
	(In thousands)	
Investments		
Insurance contract*	$ **26,697**	$ 22,656
Life insurance**	**19,115**	16,059
Other	**1,637**	4,567
Total investments	$ **47,449**	$ 43,282

* For more information on the insurance contract, see Note 6.
**Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $12.5 million in 2019 and $11.6 million in 2018.

Multiemployer plans
Intermountain contributes to a multiemployer defined benefit pension plan under the terms of a collective-bargaining agreement that covers its union-represented employees. The risks of participating in a multiemployer plan are different from a single-employer plan in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in the multiemployer plan, the Company may be required to pay the plan an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in this plan is outlined in the following table. The most recent Pension Protection Act zone status available in 2019 and 2018 is for the plan's year-end at December 31, 2018, and December 31, 2017, 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 2019	Pension Protection Act Zone Status 2018	FIP/RP Status Pending/ Implemented	Contributions 2018	Contributions 2017	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2019	Green as of 5/31/2018	No	**$ 1,307**	$ 1,247	No	03/31/2023

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, 2018 and 2017.

NOTE 12 – JOINTLY OWNED FACILITIES

The consolidated financial statements include Montana-Dakota's ownership interests in three coal-fired electric generating facilities (Big Stone Station, Coyote Station and Wygen III) and one major transmission line (BSSE). Each owner of the jointly owned facilities is responsible for financing its investment.

Montana-Dakota's share of the jointly owned facilities operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power; operation and maintenance; and taxes, other than income) in the Consolidated Statements of Income.

At December 31, Montana-Dakota's share of the cost of utility plant in service, construction work in progress and related accumulated depreciation for the jointly owned facilities was as follows:

	Ownership Percentage		2019		2018
			(In thousands)		
Big Stone Station:	22.7%				
Utility plant in service		**$**	**152,836**	$	156,534
Construction work in progress			**518**		92
Less accumulated depreciation			**46,266**		49,345
		$	**107,088**	$	107,281
BSSE:	50.0%				
Utility plant in service		**$**	**105,767**	$	—
Construction work in progress			**—**		105,846
Less accumulated depreciation			**1,232**		—
		$	**104,535**	$	105,846
Coyote Station:	25.0%				
Utility plant in service		**$**	**160,235**	$	155,236
Construction work in progress			**21**		1,920
Less accumulated depreciation			**107,638**		105,565
		$	**52,618**	$	51,591
Wygen III:	25.0%				
Utility plant in service		**$**	**67,869**	$	65,382
Construction work in progress			**112**		220
Less accumulated depreciation			**10,482**		9,174
		$	**57,499**	$	56,428

NOTE 13 – 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. As indicated below, certain regulatory proceedings and cases may also contain recurring mechanisms that can have an annual true-up. Examples of these recurring mechanisms include: infrastructure riders, transmission trackers, renewable resource cost adjustment riders, as well as weather normalization and decoupling mechanisms. The following paragraphs summarizes the Company's significant regulatory proceedings and cases by jurisdiction including the status of each open request. The Company is unable to predict the ultimate outcome of these matters, the timing of final decisions of the various regulators and courts, or the effect on the Company's results of operations, financial position or cash flows.

MNPUC

On September 27, 2019, Great Plains filed an application with the MNPUC for a natural gas rate increase of approximately $2.9 million annually or approximately 12.0 percent above current rates. The requested increase was primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. On November 22, 2019, Great Plains received approval to implement an interim rate increase of approximately $2.6 million or approximately 11.0 percent, subject to refund, effective January 1, 2020. This matter is pending before the MNPUC.

MTPSC

On November 1, 2019, Montana-Dakota submitted an application with the MTPSC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at the Heskett Station near Mandan, North Dakota. This matter is pending before the MTPSC.

NDPSC

Montana-Dakota has a transmission cost adjustment rider that allows annual updates to rates for actual costs for transmission-related projects and services. On July 19, 2019, Montana-Dakota filed a change to its transmission cost adjustment rates to reflect projected charges for July 2019 through June 2020 assessed to Montana-Dakota for transmission-related services provided by MISO and Southwest Power Pool, along with the projected transmission service revenues or credits received for the same time period. Montana-Dakota also requested recovery of six transmission capital projects. Total revenues of approximately $9.2 million, which reflects a true-up of the prior period adjustment, were requested resulting in an increase of approximately $600,000 or approximately 7.2 percent over current rates, which includes approximately $1.5 million related to transmission capital projects. On October 22, 2019, the NDPSC approved the rates as requested. The rates were effective October 28, 2019.

Montana-Dakota has a renewable resource cost adjustment rate tariff that allows for annual adjustments for recent projected capital costs and related expenses for projects determined to be recoverable under the tariff. On November 1, 2019, Montana-Dakota filed an annual update to its renewable resource cost adjustment requesting to recover a revenue requirement of approximately $14.7 million annually, not including the prior period true-up adjustment. The update reflects a decrease of approximately $800,000 from the revenues currently included in rates. On February 19, 2020, the NDPSC approved the increase with rates effective on March 1, 2020.

On August 28, 2019, Montana-Dakota filed an application with the NDPSC for an advanced determination of prudence and a certificate of public convenience and necessity to construct, own and operate Heskett Unit 4, an 88-MW simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station near Mandan, North Dakota. This matter is pending before the NDPSC.

On September 16, 2019, Montana-Dakota submitted an application with the NDPSC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. This matter is pending before the NDPSC.

OPUC

On December 29, 2017, Cascade filed a request with the OPUC to use deferred accounting for the 2018 net benefits associated with the implementation of the TCJA. On September 12, 2019, the OPUC approved the request, including a settlement to refund to customers approximately $1.4 million related to TJCA impacts for the period from January 2018 through March 2019. These refunds will be reflected in customers' rates over a 12-month period beginning November 1, 2019.

On June 14, 2019, Cascade filed a request with the OPUC to implement a new pipeline safety cost recovery mechanism to recover investments to replace Cascade's highest risk infrastructure which would have required Cascade to file a report annually with the OPUC detailing actual projects undertaken and the related costs incurred. This matter was denied by the OPUC on January 15, 2020.

SDPUC

On November 8, 2019, Montana-Dakota submitted an application with the SDPUC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. The SDPUC approved the use of deferred accounting treatment as requested on January 7, 2020.

Montana-Dakota has a transmission cost recovery rider that allows annual updates to rates for actual costs for transmission-related projects and services. On February 28, 2020, Montana-Dakota filed a change to its transmission cost recovery rates to reflect projected charges for 2020 assessed to Montana-Dakota for transmission-related services provided by MISO and Southwest Power Pool, along with the projected transmission service revenues or credits received for the same time period. Montana-Dakota also requested recovery of two transmission capital projects. Total revenues of approximately $764,000, which reflects a true-up of the prior period adjustment, were requested resulting in a decrease of approximately $15,000 or approximately 1.9 percent under current rates, which includes approximately $87,000 related to transmission capital projects. This matter is pending before the SDPUC.

Montana-Dakota has an infrastructure rider rate tariff that allows for annual adjustments for recent projected capital costs and related expenses for projects determined to be recoverable under the tariff. On February 28, 2020, Montana-Dakota filed an annual update to its infrastructure rider requesting to recover a revenue requirement of approximately $1.3 million annually, including the prior period true-up adjustment, an increase of approximately $300,000 from revenues currently included in rates. This matter is pending before the SDPUC.

WUTC

On March 29, 2019, Cascade filed a natural gas general rate case with the WUTC requesting an increase in annual revenue of $12.7 million or approximately 5.5 percent. On September 20, 2019, Cascade filed a joint settlement agreement with the WUTC reflecting a revised annual increase of approximately $6.5 million or approximately 2.8 percent with an effective date of March 1, 2020. A settlement hearing was held on November 5, 2019. On February 3, 2020, the WUTC approved the increase with rates effective on March 1, 2020.

Cascade has a pipeline replacement cost recovery mechanism, which is designed to recover the replacement cost of the Company's most at risk pipelines. The mechanism requires an annual filing on May 31, as well as two update filings for actual costs before the November 1 effective date. On May 31, 2019, Cascade filed its seventh annual update to its pipeline cost recovery mechanism requesting an increase in revenue of approximately $1.6 million or approximately 0.7 percent. On October 10, 2019, Cascade filed a final update to the cost recovery mechanism with a revised increase in revenue of approximately $440,000 or approximately 0.2 percent annually. On October 24, 2019, the WUTC approved the increase with rates effective for services provided on or after November 1, 2019.

Cascade defers the actual cost of gas spent to serve customers and annually records a true-up to their purchased gas adjustment tariff. On September 13, 2019, Cascade filed its annual update to its purchased gas adjustment with the WUTC requesting an annual increase of approximately $12.8 million or approximately 5.7 percent for a period of three years. The requested increase is primarily due to unrecovered purchased gas costs as a result of the rupture of the Enbridge pipeline in Canada on October 9, 2018, causing increased natural gas costs. On October 24, 2019, the WUTC approved the increase with rates effective for services provided on or after November 1, 2019.

WYPSC

On May 23, 2019, Montana-Dakota filed an application with the WYPSC for a natural gas rate increase of approximately $1.1 million annually or approximately 7.0 percent above current rates. The requested increase was to recover increased operating expenses and investments in distribution facilities to improve system safety and reliability. On December 17, 2019, Montana-Dakota filed a settlement agreement with the WYPSC. On January 15, 2020, the WYPSC approved the settlement, as adjusted to reflect an annual increase in revenues of approximately $828,000 or approximately 5.5 percent, with rates effective March 1, 2020.

FERC

On December 9, 2019, MISO accepted Montana-Dakota's annual revenue requirement update to its transmission formula rates under the MISO tariff for its multi-value project for approximately $13.1 million, which was effective January 1, 2020. The update effective January 1, 2020, reflects the reduced return on equity order issued by the FERC on November 21, 2019.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business 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.

At December 31, 2019 and 2018, the Company accrued liabilities, which have not been discounted, of $11.4 million and $13.4 million, respectively. The accruals are for contingencies, including litigation and environmental matters. This includes amounts that have been accrued for matters discussed in 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.

Environmental matters

Manufactured Gas Plant Sites

Claims have been made against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors and a similar claim has been made against Montana-Dakota for a site operated by Montana-Dakota and its predecessors. Any accruals related to these claims are reflected in regulatory assets. For more information, see Note 5.

Demand has been made of Montana-Dakota to participate in investigation and remediation of environmental contamination at a site in Missoula, Montana. The site operated as a former manufactured gas plant from approximately 1907 to 1938 when it was converted to a butane-air plant that operated until 1956. Montana-Dakota or its predecessors owned or controlled the site for a period of the time it operated as a manufactured gas plant and Montana-Dakota operated the butane-air plant from 1940 to 1951, at which time it sold the plant. There are no documented wastes or by-products resulting from the mixing or distribution of butane-air gas. Preliminary assessment of a portion of the site provided a recommended remedial alternative for that portion of approximately $560,000. However, the recommended remediation would not address any potential contamination to adjacent parcels that may be impacted by contamination from the manufactured gas plant. Montana-Dakota and another party agreed to voluntarily investigate and remediate the site and that Montana-Dakota will pay two-thirds of the costs for further investigation and remediation of the site. Montana-Dakota received notice from a prior insurance carrier that it will participate in payment of defense costs incurred in relation to the claim. Montana-Dakota has accrued $375,000 for the remediation of this site.

A claim was made against Cascade 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 $4.4 million has been incurred. Cascade has accrued $3.2 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 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.

A claim was made against Cascade 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. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared for one of the PRPs in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. The other PRPs will develop a cleanup action plan and, after public review of the cleanup action plan, develop design documents. 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, the plant converted 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 recorded an accrual for this site for an amount that is not material.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for certain of the contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade intends to seek recovery of remediation costs through the OPUC and WUTC in its natural gas rates charged to customers.

Purchase commitments

The Company has entered into various commitments, largely consisting of contracts for natural gas and coal supply, purchased power, and natural gas transportation and storage contracts. Certain of these contracts are subject to variability in volume and price. The commitment terms vary in length, up to 41 years.

The commitments under these contracts as of December 31, 2019, were:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Purchase commitments	$353,485	$222,156	$156,517	$121,954	$86,168	$671,245

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2019 and 2018, were $504.1 million and $450.1 million, respectively.

Guarantees

Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study, and Intermountain has an outstanding letter of credit to a third party related to gas storage costs. At December 31, 2019, the fixed maximum amount guaranteed under these letters of credit aggregated $3.6 million, which are scheduled to expire in 2020. There were no amounts outstanding under this letter of credit at December 31, 2019. In the event of default under these letter of credit obligations, the subsidiary guaranteeing the letter of credit would be obligated for reimbursement of payments made under the letter of credit.

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.

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 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, 2019, 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 $36.0 million.

NOTE 15 – RELATED-PARTY TRANSACTIONS
MDU provides and receives certain support services to/from the Company. The amount charged for services provided to the Company was $79.2 million and $62.2 million for the years ended December 31, 2019 and 2018, respectively and the amount charged for services received from the Company was $2.0 million and $5.3 million for the years ended December 31, 2019 and 2018, respectively.

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

	2019	2018
	(In thousands)	
Accounts receivable	**$ 1,327**	$ 1,883
Accounts payable	**9,606**	16,546
Dividend payable	**13,580**	4,400
Deferred charges and other assets - other	**20,614**	19,525
Deferred credits and other liabilities - other	**12,856**	11,587

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense (after tax) was $3.2 million and $2.3 million in 2019 and 2018, respectively. As of December 31, 2019, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.6 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

NOTE 16 – SUBSEQUENT EVENTS

In March 2020, the World Health Organization declared the outbreak of COVID-19 a pandemic. Measures put in place by governmental leaders to help limit the spread may have a significant impact on economic activity in the near term. The Company is monitoring the related impacts; however, it will take time before the Company can fully determine the impact of COVID-19 on the Company's results of operations, financial position and cash flows.

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)	1,106,136,156
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	42,079,946
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	1,148,216,102
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	31,106,072
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	1,179,322,174
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	508,329,146
15	Net Utility Plant (Total of lines 13 and 14)	670,993,028
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	487,657,727
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	20,671,419
22	TOTAL In Service (Total of lines 18 thru 21)	508,329,146
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)	508,329,146

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (continued)

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3		1,106,136,156		
4				
5				
6		42,079,946		
7				
8		1,148,216,102		
9				
10				
11		31,106,072		
12				
13		1,179,322,174		
14		508,329,146		
15		670,993,028		
16				
17				
18		487,657,727		
19				
20				
21		20,671,419		
22		508,329,146		
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33		508,329,146		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.
4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c).Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d),

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT		
2	301 Organization	152,066	
3	302 Franchises and Consents	211,825	
4	303 Miscellaneous Intangible Plant	44,171,295	1,915,100
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	44,535,186	1,915,100
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	112,575			45,973,820
5	112,575			46,337,711
6				
7				
8				
9				
10				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
34	345 Compressor Equipment		
35	346 Gas Measuring and Regulating Equipment		
36	347 Other Equipment		
37	348 Asset Retirement Costs for Products Extraction Plant		
38	TOTAL Products Extraction Plant (Enter Total of lines 29 thru 37)		
39	TOTAL Natural Gas Production Plant (Enter Total of lines 27 and		
40	Manufactured Gas Production Plant (Submit Supplementary		
41	TOTAL Production Plant (Enter Total of lines 39 and 40)		
42	NATURAL GAS STORAGE AND PROCESSING PLANT		
43	Underground Storage Plant		
44	350.1 Land		
45	350.2 Rights-of-Way		
46	351 Structures and Improvements		
47	352 Wells		
48	352.1 Storage Leaseholds and Rights		
49	352.2 Reservoirs		
50	352.3 Non-recoverable Natural Gas		
51	353 Lines		
52	354 Compressor Station Equipment		
53	355 Other Equipment		
54	356 Purification Equipment		
55	357 Other Equipment		
56	358 Asset Retirement Costs for Underground Storage Plant		
57	TOTAL Underground Storage Plant (Enter Total of lines 44 thru		
58	Other Storage Plant		
59	360 Land and Land Rights		
60	361 Structures and Improvements		
61	362 Gas Holders		
62	363 Purification Equipment		
63	363.1 Liquefaction Equipment		
64	363.2 Vaporizing Equipment		
65	363.3 Compressor Equipment		
66	363.4 Measuring and Regulating Equipment		
67	363.5 Other Equipment		
68	363.6 Asset Retirement Costs for Other Storage Plant		
69	TOTAL Other Storage Plant (Enter Total of lines 58 thru 68)		
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant		
71	364.1 Land and Land Rights		
72	364.2 Structures and Improvements		
73	364.3 LNG Processing Terminal Equipment		
74	364.4 LNG Transportation Equipment		
75	364.5 Measuring and Regulating Equipment		
76	364.6 Compressor Station Equipment		
77	364.7 Communications Equipment		
78	364.8 Other Equipment		
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas		
80	TOTAL Base Load Liquefied Nat'l Gas, Terminaling and Processing		

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

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
34				
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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	22,171,656	
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment	180,823	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant	87,720	
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	23,690,824	
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,663,807	(1,069)
95	375 Structures and Improvements	1,465,897	26,722
96	376 Mains	506,416,844	35,945,433
97	377 Compressor Station Equipment	2,097,767	
98	378 Measuring and Regulating Station Equipment-General	33,041,936	3,898,812
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	249,437,259	20,302,027
101	381 Meters	65,020,482	7,381,151
102	382 Meter Installations	33,655,296	258,770
103	383 House Regulators	11,160,435	747,583
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	11,641,827	606,385
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	22,097,038	4,194,531
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	938,698,588	73,360,345
110	GENERAL PLANT		
111	389 Land and Land Rights	3,468,083	529,808
112	390 Structures and Improvements	20,024,461	2,955,411
113	391 Office Furniture and Equipment	8,287,578	382,123
114	392 Transportation Equipment	17,137,416	2,637,485
115	393 Stores Equipment	66,925	9,277
116	394 Tools, Shop, and Garage Equipment	8,967,475	514,296
117	395 Laboratory Equipment	119,908	
118	396 Power Operated Equipment	4,989,380	2,970,885
119	397 Communication Equipment	7,159,952	445,056
120	398 Miscellaneous Equipment	80,968	
121	Subtotal (Enter Total of lines 111 thru 120)	70,302,146	10,444,341
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)	70,302,146	10,444,341
125	TOTAL (Accounts 101 and 106)	1,077,226,744	85,719,786
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)	1,077,226,744	85,719,786

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	68,126			22,103,530
87				
88				180,823
89				
90				
91	1,083			86,637
92	69,209			23,621,615
93				
94	8,900		57,231	2,711,069
95	4,279			1,488,340
96	460,859			541,901,418
97				2,097,767
98	185,672		(31,426)	36,723,650
99				
100	224,123			269,515,163
101	7,399,688			65,001,945
102	27,453		(39,331)	33,847,282
103	388,253			11,519,765
104				
105	101,506		13,526	12,160,232
106				
107				
108	40,375			26,251,194
109	8,841,108			1,003,217,825
110				
111				3,997,891
112	10,642			22,969,230
113				8,669,701
114	1,481,853			18,293,048
115				76,202
116	90,786			9,390,985
117	30,186			89,722
118	4,094,069			3,866,196
119				7,605,008
120				80,968
121	5,707,536			75,038,951
122				
123				
124	5,707,536			75,038,951
125	14,730,428			1,148,216,102
126				
127				
128				
129	14,730,428			1,148,216,102

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Property and Capacity Leased from Others

1. Report below the information called for concerning gas property and capacity leased from others for gas operations.
2. For all leases in which the average annual lease payment over the initial term of the lease exceeds $500,000, describe in column (c), if applicable: the property or capacity leased. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
1	None			
2				
3				
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45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Property and Capacity Leased to Others

1. For all leases in which the average lease income over the initial term of the lease exceeds $500,000 provide in column (c), a description of each facility or leased capacity that is classified as gas plant in service, and is leased to others for gas operations.
2. In column (d) provide the lease payments received from others.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
1	None			
2				
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45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Plant Held for Future Use (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $1,000,000 or more. Group other items of property held for future use.
2. For property having an original cost of $1,000,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	None			
2				
3				
4				
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45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Reinforce 12" main form new Wallula Gate in Burbank, WA	7,816,137	
2	Construct Wallula gate station	5,577,632	
3	Upgrade Willaim's facilities at Othello, WA lateral	2,510,544	
4	Reinforce 6" main in Arlington, WA	2,426,962	
5	Anacortes lateral upgrade and main replacement	2,363,557	
6			
7			
8	Minor distribution system/general Plant projects each under		
9	$1 million	10,411,240	
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45	**Total**	**31,106,072**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Non-Traditional Rate Treatment Afforded New Projects

1. The Commission's Certificate Policy Statement provides a threshold requirement for existing pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. See Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC P61,227 (1999); order clarifying policy, 90 FERC P61,128 (2000); order clarifying policy, 92 FERC P61,094 (2000) (Policy Statement). In column a, list the name of the facility granted non-traditional rate treatment.
2. In column b, list the CP Docket Number where the Commission authorized the facility.
3. In column c, indicate the type of rate treatment approved by the Commission (e.g. incremental, at risk)
4. In column d, list the amount in Account 101, Gas Plant in Service, associated with the facility.
5. In column e, list the amount in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant, associated with the facility.

Line No.	Name of Facility (a)	CP Docket No. (b)	Type of Rate Treatment (c)	Gas Plant in Service (d)
1	None			
2				
3				
4				
5				
6				
7				
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9				
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	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							
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General Description of Construction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

1. Engineering & Supervision and General & Administrative overhead:

Engineer & Supervision (ES) overhead consists of employees' time in preparation of work orders, mapping, determining feasibility, and other Engineering/construction based supervisory costs related to new construction which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

General & Administrative (GA) overhead consists of employees' time in processing A/P, A/R, receiving orders,and other administrative functions which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

Both ES & GA (ES/GA) are accumulated in pools from which a portion is allocated each month. The allocation is based on a rate determined by the Fixed 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 is capital installation/purchase, and not a preliminary survey or investigative in nature. Note that purchase projects only receive GA overhead, not ES. Construction projects receive both.

2. ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION (AFUDC):

The formula on page 218a is used.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

General Description of Construction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

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

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

Line No.	Title (a)		Amount (b)	Capitalization Ration (percent) (c)		Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S	72,533,718	[redacted]		[redacted]
	(2) Short-Term Interest		[redacted]	[redacted]	s	3.96
	(3) Long-Term Debt	D	214,361,000	45.30	d	5.27
	(4) Preferred Stock	P			p	
	(5) Common Equity	C	258,853,904	54.70	c	9.40
	(6) Total Capitalization		473,214,904	100.00		[redacted]
	(7) Average Construction Work In Progress Balance	W	18,920,510	[redacted]		[redacted]

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] 3.96

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

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 3.96

b. Rate for Other Funds -

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 10, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	(473,404,421)	(473,404,421)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(29,230,448)	(29,230,448)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(1,225,783)	(1,225,783)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(325,524)	(325,524)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(30,781,755)	(30,781,755)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	14,617,853	14,617,853		
13	Cost of Removal	1,734,434	1,734,434		
14	Salvage (Credit)	3,670,523	3,670,523		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	12,681,764	12,681,764		
16	Other Debit or Credit Items (Describe) (footnote details):	3,846,686	3,846,686		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(487,657,726)	(487,657,726)		
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Productions-Manufactured Gas				
22	Production and Gathering-Natural Gas				
23	Products Extraction-Natural Gas				
24	Underground Gas Storage				
25	Other Storage Plant				
26	Base Load LNG Terminaling and Processing Plant				
27	Transmission	(16,055,235)	(16,055,235)		
28	Distribution	(445,691,515)	(445,691,515)		
29	General	(25,910,976)	(25,910,976)		
30	TOTAL (Total of lines 21 thru 29)	(487,657,726)	(487,657,726)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Stored (Accounts 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, and 164.3)

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.
2. Report in column (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.
3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e., fixed asset method or inventory method).

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of					396,659	1,940,549		2,337,208
2	Gas Delivered to Storage						2,167,637		2,167,637
3	Gas Withdrawn from						2,264,049		2,264,049
4	Other Debits and Credits					497,000			497,000
5	Balance at End of Year					893,659	1,844,137		2,737,796
6	Dth					226,482	575,503		801,985
7	Amount Per Dth					3.9458	3.2044		3.4138

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Investments (Account 123, 124, and 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments.
2. Provide a subheading for each account and list thereunder the information called for:
   (a) Investment in Securities-List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments) state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes.
   (b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances that are properly includable in Account 123. Include advances subject to current repayment in Account 145 and 146. With respect to each advance, show whether the advance is a note or open account.

Line No.	Description of Investment (a)	* (b)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (c)	Purchases or Additions During the Year (d)
1				
2	Account 124			
3	Oregon weatherization loans			
4	Customer Note Receivable			
5	SERP Plan Assets		12,232,178	894,631
6	SISP Plan Assets		139,137	
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				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	1,135,267		11,991,542	894,631	
6	139,137				
7					
8					
9					
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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				
8				
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40	**TOTAL Cost of Account 123.1 $**		**TOTAL**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Investments in Subsidiary Companies (Account 123.1) (continued)

4. Designate in a footnote, any securities, notes, or accounts that were pledged, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report in column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost), and the selling price thereof, not including interest adjustments includible in column (f).
8. Report on Line 40, column (a) the total cost of Account 123.1.

Line No.	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1				
2				
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4				
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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	138,018
2	Prepaid Rents	3,853,771
3	Prepaid Taxes	969,544
4	Prepaid Interest	
5	Miscellaneous Prepayments	541,312
6	TOTAL	5,502,645

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

EXTRAORDINARY PROPERTY LOSSES (ACCOUNT 182.1)

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

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (ACCOUNT 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Charges (c)	Costs Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
16	None						
17							
18							
19							
20							
21							
22							
23							
24							
25							
26	**Total**						

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Other Regulatory Assets (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1							
2	FAS158 Regultory Asset	48,588,659	(7,129,974)				41,458,685
3	(Total system asset)						
4							
5	OR MAOP Regulatory Asset	572,923	(572,923)				
6	(OR regulatory asset)						
7							
8	WA Conservation	7,007,263	(201,813)				6,805,450
9	(WA regulatory asset)						
10							
11							
12							
13							
14							
15							
16							
17							
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39							
40	**Total**	**56,168,845**	**(7,904,710)**		**0**	**0**	**48,264,135**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Miscellaneous Deferred Debits (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	WA Bremerton Manufactured Gas Plant	14,082,715	114,067	9230	1,604,646	12,592,136
2	Remediation					
3						
4	WA Bellingham Manufactured Gas Plant	466,500		9230		466,500
5						
6	WA Decoupling Adjustment	(4,075,396)	10,310,883	4800-4813	9,228,416	(2,992,929)
7						
8	WA MAOP Deferred Costs	10,629,138	2,585,914	9230	544,889	12,670,163
9						
10	WA Over Refunded Temp FIT		277,480			277,480
11						
12	OR Conservation Programs	(444,461)	5,986,637	4800-4813	7,326,747	(1,784,571)
13				4890		
14	OR Eugene Manufactured Gas Plant	1,954,226	266,270	9230,4890	1,006,036	1,214,460
15	Remediation			4800-4813		
16						
17	OR Intervenor Funding	42,167	226,353	4800-4813	175,656	92,864
18				4890		
19	OR MAOP		583,275		145,819	437,456
20						
21	I/C Asset - Net Benefit Funds	4,405,213	709,004			5,114,217
22						
23	Post Retirement FAS 158	2,988,574	1,571,540	9260	81,721	4,478,393
24						
25	ARO	49,007,788	4,077,136		439,732	52,645,192
26						
27						
28						
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38						
39	Miscellaneous Work in Progress					
40	**Total**	**79,056,464**	**26,708,559**		**20,553,662**	**85,211,361**

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[Next page is 234]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Accumulated Deferred Income Taxes (Account 190)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric			
3	Gas	17,102,003	12,657,011	11,570,300
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	17,102,003	12,657,011	11,570,300
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	17,102,003	12,657,011	11,570,300
8	Classification of TOTAL			
9	Federal Income Tax	15,725,604	11,672,828	10,669,511
10	State Income Tax	1,376,399	984,183	900,789
11	Local Income Tax			

Accumulated Deferred Income Taxes (Account 190) (continued)

Line No.	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3	762,822	59,042	footnote	(1,019,871)	footnote	(8,179,495)	8,151,888
4							
5	762,822	59,042		(1,019,871)		(8,179,495)	8,151,888
6							
7	762,822	59,042		(1,019,871)		(8,179,495)	8,151,888
8							
9	702,510	55,372		(1,007,569)		(7,586,907)	7,495,811
10	60,312	3,670		(12,302)		(592,588)	656,077
11							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Capital Stock (Accounts 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common stock - not publicly traded	1,000	1.00	
3				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Capital Stock (Accounts 201 and 204)

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Outstanding per Bal. Sheet (total amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1						
2	1,000	1,000				
3						
4						
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Capital Stock: Subscribed, Liability for Conversion, Premium on, and Installments Recieved on (Accts 202, 203, 205, 206, 207, and 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of year.
4. For Premium on Account 207, Capital Stock, designate with an asterisk in column (b), any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	* (b)	Number of Shares (c)	Amount (d)
1	Account 207			
2	Premium on Capital Stock - Common		1,000	266,117,553
3				
4	Represents excess received over $1.00 par value			
5	of common stock			
6				
7				
8				
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40	**Total**		**1,000**	**266,117,553**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Other Paid-In Capital (Accounts 208-211)

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	None	
2		
3		
4		
5		
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40	**Total**	**0**

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
16	None	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
	TOTAL	

Securities Issued or Assumed and Securities Refunded or Retired During the Year

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

None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Long-Term Debt (Accounts 221, 222, 223, and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)
1	Account 224			
2				
3	Other Long Term Debt:			
4				
5	Medium Term Notes	09/15/1997	09/15/2027	20,000,000
6	Medium Term Notes	03/16/1999	03/16/2029	15,000,000
7	Insured Quarterly Notes	02/01/2005	02/01/2035	24,214,000
8	Notes	09/01/2005	09/01/2020	15,000,000
9	Senior Notes	03/08/2007	03/08/2037	40,000,000
10	Senior Notes (Series A)	08/23/2013	08/23/2025	25,000,000
11	Senior Notes (Series B)	08/23/2013	08/23/2028	25,000,000
12	Senior Notes (Series A)	11/24/2014	11/24/2044	12,500,000
13	Senior Notes (Series B)	11/24/2014	11/24/2054	12,500,000
14	Senior Notes (Series C)	01/15/2015	01/15/2045	12,500,000
15	Senior Notes (Series D)	01/15/2015	01/15/2055	12,500,000
16	Senior Notes	06/13/2019	06/13/2028	25,000,000
17	Senior Notes	06/13/2019	06/13/2034	20,000,000
18	Senior Notes	06/13/2019	06/13/2049	30,000,000
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40	**TOTAL**			289,214,000

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Long-Term Debt (Accounts 221, 222, 223, and 224)

5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Interest for Year Rate (in %) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1					
2					
3					
4					
5	7.480	1,496,000			
6	7.100	1,064,700			
7	5.250	956,196			
8	5.210	781,500			
9	5.790	2,316,000			
10	4.110	1,027,500			
11	4.360	1,090,000			
12	4.090	511,250			
13	4.240	530,000			
14	4.090	511,250			
15	4.240	530,000			
16	3.620	527,917			
17	3.820	445,667			
18	4.260	745,500			
19					
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40		12,533,480			

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.
2. Show premium amounts by enclosing the figures in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	Amortization Period Date From (d)	Amortization Period Date To (e)
1	Unamortized Debt Expense (Account 181)				
2					
3	Medium Term Notes 7.48%	20,000,000	201,406	09/15/1997	09/15/2027
4	Medium Term Notes 7.10%	15,000,000	151,056	03/16/1999	03/16/2029
5	Insured Quarterly Notes 5.25%	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		236,967	04/25/2017	04/24/2020
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	Senior Notes 3.62%	25,000,000	128,459	06/13/2019	06/13/2028
16	Senior Notes 3.82%	20,000,000	102,768	06/13/2019	06/13/2034
17	Senior Notes 4.26%	30,000,000	154,151	06/13/2019	06/13/2049
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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	58,464		6,714	51,750
4	51,190		5,035	46,155
5	852,667		57,841	794,826
6	25,296		16,176	9,120
7	141,205		7,770	133,435
8	82,845		12,584	70,261
9	96,477		10,067	86,410
10	98,736	395,739	144,906	349,569
11	53,781		2,082	51,699
12	54,740		1,527	53,213
13	54,128		2,082	52,046
14	54,995		1,528	53,467
15		158,379	37,413	120,966
16		126,748	27,977	98,771
17		175,495	24,341	151,154
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Unamortized Loss and Gain on Reacquired Debt (Accounts 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.
2. In column (c) show the principal amount of bonds or other long-term debt reacquired.
3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform Systems of Accounts.
4. Show loss amounts by enclosing the figures in parentheses.
5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt, or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal of Debt Reacquired (c)	Net Gain or Loss (d)	Balance at Beginning of Year (e)	Balance at End of Year (f)
1	Unamortized Loss on					
2	Reacquired Debt (Acct 189)					
3						
4						
5	7.50% Notes					
6	Due 11/15/2031 (1)	11/15/2001	39,729,000	(1,229,120)	744,300	703,330
7						
8	See footnote					
9						
10						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Reconciliation of Reported Net Income with Taxable Income for Feder Income Taxes

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal Income Tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	16,328,047
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Section 174 costs	4,458,050
6	CIAC	1,031,570
7	see footnote	480,991
8	TOTAL	5,970,611
9	Deductions Recorded on Books Not Deducted for Return	
10	see footnote	39,831,921
11		
12		
13	TOTAL	39,831,921
14	Income Recorded on Books Not Included in Return	
15	see footnote	(4,335,799)
16		
17		
18	TOTAL	(4,335,799)
19	Deductions on Return Not Charged Against Book Income	
20	see footnote	(100,550,267)
21		
22		
23		
24		
25		
26	TOTAL	(100,550,267)
27	Federal Tax Net Income	(42,755,488)
28	Show Computation of Tax:	
29	Rate - 21.00%	
30	Estimated Tax Return Federal Income Tax	(8,978,652)
31	Adjustments: (see footnote)	(1,959,703)
32	Provision for Current Federal Income Tax (see footnote)	(10,938,355)
33	Oregon State Tax Calculation (see footnote)	(1,030,481)
34		
35		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to the portion of prepaid taxes charged to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)	Balance at Beg. of Year Taxes Accrued (b)	Balance at Beg. of Year Prepaid Taxes (c)
1	Income Tax		
2	Oregon Accrued		810,941
3	Federal Accrued		10,266,423
4	Fin 48 - current		(71,714)
5	Gross Revenue		
6	Washington	460,551	
7	Oregon		
8	Dept of Energy - Oregon		34,488
9	City Franchise & Occupation		
10	Washington	1,459,325	
11	Oregon	709,456	
12	Property		
13	Washington	2,609,583	
14	Oregon		843,102
15	Payroll Taxes	318,833	
16	State Excise - Washington	1,727,418	
17			
18	Miscellaneous		
19			
20			
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	TOTAL	7,285,166	11,883,240

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		(941,388)		(89,093)
3		(11,554,498)		587,143
4		29,000		
5				
6		467,666		
7		187,024		
8		78,672		
9				
10		10,763,808		
11				
12				
13		2,357,061		
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	TOTAL	1,387,345		498,050

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged) (continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in columns (i) thru (p) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

Line No.	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (h)
1					
2	(1,030,481)	(1,559,406)			282,016
3	(10,967,355)	(17,871,127)			3,362,651
4	32,227				(103,941)
5					
6	467,666	448,919		479,297	
7	187,024	187,023			(1)
8	78,672	74,573			30,389
9					
10	10,763,808	10,302,282		1,920,851	
11		(210,836)		920,292	
12					
13	2,357,061	2,173,658		2,792,986	
14		96,054			939,156
15	(173,860)	(273,837)		418,810	
16	(9,881)	(575,652)		2,293,189	
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TOTAL	1,704,881	(7,208,349)		8,825,425	4,510,270

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged) (continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in columns (i) thru (p) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)
1					
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TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Miscellaneous Current and Accrued Liabilities (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	Vacation Payable	2,137,261
2	Wages Payable	1,925,851
3	Variable Pay Incentive	1,697,134
4	Accrued 401K Defined Contributions	1,244,918
5	Oregon Weatherization Liability	1,017,469
6	Washington Low Income Bill Assistance	617,037
7	SERP Defined Contributions	554,325
8	Energy Trust of Oregon Liability	532,108
9	Oregon Conservation Achievement Tariff	(490,972)
10	Other Misc Current Liabilities (aggregate)	357,705
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45	**Total**	**9,592,836**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	WA Deferred Gas Costs	(40,887,967)	805.1	194,602,426	151,402,919	(84,087,474)
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	(593,187)	805.1	29,544,849	25,159,378	(4,978,658)
5	(ammortization period 11/11-present)					
6						
7	SGL Deposit	48,270	134/288.4	24,135		24,135
8	Customer Unclaimed Credits	(122)	131	100,946	383	(100,685)
9	MDUR Interco Pension	974,030	228.3/182	43,279	114,859	1,045,610
10	Pension Contribution	9,444,730	various	3,101,351	356,388	6,699,767
11	MDUR Inerco Post-Retirment		228.3/182	197,919		(197,919)
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45	**Total**	**(31,014,246)**		**227,614,905**	**177,033,927**	**(81,595,224)**

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	(53,594,339)	(4,691,709)	(2,939,172)
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(53,594,339)	(4,691,709)	(2,939,172)
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(53,594,339)	(4,691,709)	(2,939,172)
8	Classification of TOTAL			
9	Federal Income Tax	(49,763,427)	(4,173,671)	(2,778,836)
10	State Income Tax	(3,830,912)	(518,038)	(160,336)
11	Local Income Tax			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	102,647,993	182.3&254	105,168,567	(57,867,450)
4							
5				102,647,993		105,168,567	(57,867,450)
6							
7				102,647,993		105,168,567	(57,867,450)
8							
9			254	102,570,773	254	105,096,084	(53,683,573)
10			182.3	77,220	182.3	72,483	(4,183,877)
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	(34,901,601)	(27,691,005)	(19,054,142)
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(34,901,601)	(27,691,005)	(19,054,142)
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	(34,901,601)	(27,691,005)	(19,054,142)
8	Classification of TOTAL			
9	Federal Income Tax	(31,839,495)	(25,500,861)	(17,658,724)
10	State Income Tax	(3,062,106)	(2,190,144)	(1,395,418)
11	Local Income Tax			

Accumulated Deferred Income Taxes-Other (Account 283) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			footnote	7,699,041	footnote	1,630,337	(37,469,760)
4							
5				7,699,041		1,630,337	(37,469,760)
6							
7				7,699,041		1,630,337	(37,469,760)
8							
9				7,080,815		1,600,148	(34,200,965)
10				618,226		30,189	(3,268,795)
11							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Other Regulatory Liabilities (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	Oregon Unbilled Ammortization	(151,305)	4009			(27,933)	(179,238)
2	Washington Unbilled Ammortization	(934,952)	4009			745,548	(189,404)
3	SFAS109 Regulatory Liability	49,624,465	282			(2,520,574)	47,103,891
4	Oregon Tax Rate Change	9,124,558	282			(1,161,173)	7,963,385
5	Regulatory Liability - Post Ret FAS158	2,706,980	186			(2,706,980)	
6	WA Protected - Plus EDIT	1,000,748	4962	1,499,413		1,513,156	1,014,491
7	WA Protected - Plus EDIT grossup	274,816	4962	483,643		437,437	228,610
8	WA Unprotected EDIT	463,561	4962	669,848		657,046	450,759
9	WA Unprotected EDIT grossup	126,337	4962	216,889		189,945	99,393
10	WA Temp Fed Income Tax Credit	863,200	4962	1,040,739		177,539	
11	WA Temp Fed Income Tax Credit grossup	236,936	4962	336,877		99,941	
12	WA Diff Temp Fed Income Tax Credit	(367,551)	4962			367,551	
13	OR Unprotected EDIT		4962	162,031		1,004,662	842,631
14	OR Temp Fed Income Tax Credit		4962	228,628		1,400,000	1,171,372
15							
16							
17							
18							
19							
20							
21							
22							
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42							
43							
44							
45	**Total**	**62,967,793**		**4,638,068**	**0**	**176,165**	**58,505,890**

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Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Gas Operating Revenues

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480 Residential Sales				
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartmental Sales				
6	485 Intracompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenues from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natural Gas				
14	491 Revenues from Natural Gas Proc. by Others				
15	492 Incidental Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartmental Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	TOTAL:				

Gas Operating Revenues

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	172,399,518	161,603,290	172,399,518	161,603,290	18,083,127	16,285,884
2	111,750,808	100,897,968	111,750,808	100,897,968	17,273,373	15,106,021
3						
4						
5						
6						
7						
8	697,653	925,187	697,653	925,187		
9						
10						
11	28,526,904	27,132,008	28,526,904	27,132,008	108,892,465	94,156,657
12						
13						
14						
15						
16	182,208	125,412	182,208	125,412		
17						
18	104,949	124,553	104,949	124,553		
19	313,662,040	290,808,418	313,662,040	290,808,418		
20	(733,536)	3,982,745	(733,536)	3,982,745		
21	314,395,576	286,825,673	314,395,576	286,825,673		

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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

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

Line No.	Rate Schedule and Zone of Receipt (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Current Year (d)
1	N/A				
2					
3					
4					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e).
4. Delivered Dth of gas must not be adjusted for discounting.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
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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 Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	N/A				
2					
3					
4					
5					
6					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Revenues from Transportation of Gas of Others Through Transmission Facilities (Account 489.2)

4. Delivered Dth of gas must not be adjusted for discounting.
5. Each incremental rate schedule and each individually certificated rate schedule must be separately reported.
6. Where transportation services are bundled with storage services, report total revenues but only transportation Dth.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Revenues from Storing Gas of Others (Account 489.4)

1. Report revenues and Dth of gas withdrawn from storage by Rate Schedule and in total.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other revenues in columns (f) and (g) include reservation charges, deliverability charges, injection and withdrawal charges, less revenues reflected in columns (b) through (e).

Line No.	Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	N/A				
2					
3					
4					
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Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Revenues from Storing Gas of Others (Account 489.4)

4. Dth of gas withdrawn from storage must not be adjusted for discounting.
5. Where transportation services are bundled with storage services, report only Dth withdrawn from storage.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Other Gas Revenues (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Miscellaneous Sales	104,949
13		
14		
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	Total	**104,949**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Discounted Rate Services and Negotiated Rate Services

1. In column b, report the revenues from discounted rate services.
2. In column c, report the volumes of discounted rate services.
3. In column d, report the revenues from negotiated rate services.
4. In column e, report the volumes of negotiated rate services.

Line No.	Account (a)	Discounted Rate Services Revenue (b)	Discounted Rate Services Volumes (c)	Negotiated Rate Services Revenue (d)	Negotiated Rate Services Volumes (e)
1	Account 489.1, Revenues from transportation of gas of others through gathering facilities.				
2	Account 489.2, Revenues from transportation of gas of others through transmission facilities.				
3	Account 489.4, Revenues from storing gas of others.				
4	Account 495, Other gas revenues.				
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37					
38					
39					
	Total				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Operation and Maintenance Expenses

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

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	221,421,972	177,359,949
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	63,979,796	37,057,421
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	157,442,176	140,302,528
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	7,301,670	4,132,771
87	(Less) 808.2 Gas Delivered to Storage-Credit	8,003,476	4,963,076
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	85,398	59,074
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	85,398	59,074
95	813 Other Gas Supply Expenses	431,005	329,878
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	157,085,977	139,743,027
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	157,085,977	139,743,027
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	2,922,135	3,119,233
205	871 Distribution Load Dispatching	397,129	378,468
206	872 Compressor Station Labor and Expenses	37,041	70,484
207	873 Compressor Station Fuel and Power	0	0

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

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	5,473,338	5,290,540
209	875 Measuring and Regulating Station Expenses-General	571,593	644,834
210	876 Measuring and Regulating Station Expenses-Industrial	157,467	201,756
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,310,032	1,297,445
213	879 Customer Installations Expenses	895,735	1,004,698
214	880 Other Expenses	6,924,705	6,062,842
215	881 Rents	131,335	149,387
216	TOTAL Operation (Total of lines 204 thru 215)	18,820,510	18,219,687
217	Maintenance		
218	885 Maintenance Supervision and Engineering	1,342,630	1,207,024
219	886 Maintenance of Structures and Improvements	1,106	21,819
220	887 Maintenance of Mains	1,936,835	1,850,162
221	888 Maintenance of Compressor Station Equipment	73,765	56,633
222	889 Maintenance of Measuring and Regulating Station Equipment-General	457,161	539,529
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	65,334	47,779
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	1,627,916	1,774,738
226	893 Maintenance of Meters and House Regulators	1,244,278	1,266,814
227	894 Maintenance of Other Equipment	1,496,435	1,203,286
228	TOTAL Maintenance (Total of lines 218 thru 227)	8,245,460	7,967,784
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	27,065,970	26,187,471
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	145,763	141,146
233	902 Meter Reading Expenses	795,972	796,415
234	903 Customer Records and Collection Expenses	5,478,654	5,489,472

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	1,209,258	866,122
236	905 Miscellaneous Customer Accounts Expenses	131,810	7
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	7,761,457	7,293,162
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	7,080,082	4,222,388
242	909 Informational and Instructional Expenses	180,176	30,583
243	910 Miscellaneous Customer Service and Informational Expenses	359,135	342,654
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	7,619,393	4,595,625
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	4,232	0
249	913 Advertising Expenses	3,250	2,839
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	7,482	2,839
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	8,804,332	7,483,551
255	921 Office Supplies and Expenses	4,523,492	4,162,213
256	(Less) 922 Administrative Expenses Transferred-Credit	415,349	357,025
257	923 Outside Services Employed	783,986	1,591,557
258	924 Property Insurance	110,370	81,986
259	925 Injuries and Damages	1,661,441	1,572,433
260	926 Employee Pensions and Benefits	6,951,421	5,779,296
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	214,339	0
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	35,333	30,629
265	930.2Miscellaneous General Expenses	1,032,639	1,171,419
266	931 Rents	1,445,125	1,569,366
267	TOTAL Operation (Total of lines 254 thru 266)	25,147,129	23,085,425
268	Maintenance		
269	932 Maintenance of General Plant	57,274	37,362
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	25,204,403	23,122,787
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	224,744,682	200,944,911

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Exchange and Imbalance Transactions

1. Report below details by zone and rate schedule concerning the gas quantities and related dollar amount of imbalances associated with system balancing and no-notice service. Also, report certificated natural gas exchange transactions during the year. Provide subtotals for imbalance and no-notice quantities for exchanges. If respondent does not have separate zones, provide totals by rate schedule. Minor exchange transactions (less than 100,000 Dth) may be grouped.

Line No.	Zone/Rate Schedule (a)	Gas Received from Others Amount (b)	Gas Received from Others Dth (c)	Gas Delivered to Others Amount (d)	Gas Delivered to Others Dth (e)
1	None				
2					
3					
4					
5					
6					
7					
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9					
10					
11					
12					
13					
14					
15					
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23					
24					
25	**Total**	**0**	**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Used in Utility Operations

1. Report below details of credits during the year to Accounts 810, 811, and 812.
2. If any natural gas was used by the respondent for which a charge was not made to the appropriate operating expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit					
2	811 Gas Used for Products Extraction - Credit					
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others					
5	812 Gas Used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses.)	812	37,101	85,398		
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7						
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9						
10						
11						
12						
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14						
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25	**Total**		37,101	85,398		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Transmission and Compression of Gas by Others (Account 858)

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

Line No.	Name of Company and Description of Service Performed (a)	* (b)	Amount of Payment (in dollars) (c)	Dth of Gas Delivered (d)
1	None			
2				
3				
4				
5				
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24				
25	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Other Gas Supply Expenses (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1	Labor expenses and applicable overhead charges	308,840
2	Puget Sound Energy - Fredonia	85,011
3	Training materials	53,623
4	Lodging	16,614
5	Software Maintenance	14,311
6	Meals & Entertainment	8,404
7	Commercial air service	8,358
8	Vehicle mileage	957
9	Office supplies	144
10	Other advertising	84
11		
12		
13		
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23		
24		
25	**Total**	496,346

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.	284,608
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	Director's fees (paid to MDU for CNGC's share of director's expenses)	451,891
6	Miscellaneous under $250,000	296,140
7	2,418 items	
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25	**Total**	1,032,639

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are

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

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant				3,457,659
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	420,168			
9	Distribution plant	27,346,458			
10	General plant	1,463,822			
11	Common plant-gas				
12	TOTAL	29,230,448			3,457,659

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments) (continued)

obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

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

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

Line No.	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1			3,457,659	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			420,168	Transmission plant
9			27,346,458	Distribution plant
10			1,463,822	General plant
11				Common plant-gas
12			32,688,107	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 year, and the period of amortization.

(b) Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) - Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	(a) Miscellaneous Amortization (Account 425)	
2		
3	(b) Miscellaneous Income Deductions (Account 426)	
4	Donations (Account 426.1)	251,619
5	Life Insurance (Account 426.2)	
6	Penalties (Accont 426.3)	94
7	Expenditures for Certain Civic, Political and Related Activities	
8	(Account 426.4)	306,254
9	Other Deductions (Account 426.5)	1,556
10	Total Miscellaneous Income Deductions (Account 426)	559,523
11		
12	(c) Interest on Debt to Associated Companies (Account 430)	
13		
14	(d) Other Interest Expense (Account 431)	
15		
16	Customer Deposits-OR Various	4,568
17	Customer Deposits-WA Various	16,600
18	Deferral Accounts-OR ***	92,378
19	Deferral Accounts-WA FERC Interest Rate	296,643
20	Interest on Short-Term Debt Various	916,126
21	Other Various	36,480
22	Total Other Interest Expense (Account 431)	1,362,795
23		
24	***Accounts not amortizing-7.284% (Jan-Mar) and 7.270%(Apr-Dec);	
25	Accounts amortizing-2.92% (Jan-Oct) and 3.74% (Nov-Dec),	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
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24					
25	**Total**				

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Regulatory Commission Expenses (Account 928)

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

Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1							
2							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Employee Pensions and Benefits (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits.

Line No.	Expense (a)	Amount (b)
1	Pensions – defined benefit plans	167,211
2	Pensions – other	1,959,406
3	Post-retirement benefits other than pensions (PBOP)	(169,774)
4	Post- employment benefit plans	
5	Other (Specify)	
6	Medical/Dental	3,072,649
7	Various	167,539
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
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	Total	**5,197,031**

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Distribution of Salaries and Wages

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production				
4	Transmission				
5	Distribution				
6	Customer Accounts				
7	Customer Service and Informational				
8	Sales				
9	Administrative and General				
10	TOTAL Operation (Total of lines 3 thru 9)				
11	Maintenance				
12	Production				
13	Transmission				
14	Distribution				
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)				
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)				
19	Transmission (Total of lines 4 and 13)				
20	Distribution (Total of lines 5 and 14)				
21	Customer Accounts (line 6)				
22	Customer Service and Informational (line 7)				
23	Sales (line 8)				
24	Administrative and General (Total of lines 9 and 15)				
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)				
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply				
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution	12,443,276			12,443,276
34	Customer Accounts	3,990,039			3,990,039
35	Customer Service and Informational	859,885			859,885
36	Sales	3,785			3,785
37	Administrative and General	6,030,175			6,030,175
38	TOTAL Operation (Total of lines 28 thru 37)	23,327,160			23,327,160
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	5,195,942			5,195,942

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)	5,195,942			5,195,942
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)				
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	17,639,218			17,639,218
56	Customer Accounts (Total of line 34)	3,990,039			3,990,039
57	Customer Service and Informational (Total of line 35)	859,885			859,885
58	Sales (Total of line 36)	3,785			3,785
59	Administrative and General (Total of lines 37 and 46)	6,030,175			6,030,175
60	Total Operation and Maintenance (Total of lines 50 thru 59)	28,523,102			28,523,102
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	28,523,102			28,523,102
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	7,636,223			7,636,223
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	7,636,223			7,636,223
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	711,998			711,998
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	711,998			711,998
75	Other Accounts (Specify) (footnote details)	1,697,135			1,697,135
76	TOTAL Other Accounts	1,697,135			1,697,135
77	TOTAL SALARIES AND WAGES	38,568,458			38,568,458

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising,labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.
(a) Name of person or organization rendering services.
(b) Total charges for the year.
2. Sum under a description “Other”, all of the aforementioned services amounting to $250,000 or less.
3. Total under a description “Total”, the total of all of the aforementioned services.
4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	Michels Corporation	34,006,160
2	Brothers Pipeline Corp.	7,982,855
3	Infrasource Construction, LLC	5,244,613
4	Gas Transmission NW Corp.	5,200,000
5	Southern Cross	2,829,981
6	Northwest Metal Fab	2,771,405
7	Hanging H Companies, LLC	2,600,084
8	Northwest Pipeline, LLC	2,500,000
9	Mackay & Sposito, Inc.	1,340,703
10	Parametrix, Inc.	1,137,413
11	Mistras Group, Inc.	883,839
12	Lockheed Martin Energy	773,659
13	Eugene Water & Electric Board	743,205
14	Five Rivers Construction, Inc.	718,904
15	Anchor QEA	675,648
16	Mesa Products	632,581
17	NW Pipeline, LLC	498,600
18	Aspect Consulting, LLC	481,260
19	Snyder Gas Consulting, LLC	478,297
20	Infrasource Services, LLC	397,320
21	Northwest Inspection, Inc.	303,345
22	Deloitte & Touche	276,126
23	JUB Engineers, Inc.	257,748
24	Other	1,729,052
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Transactions with Associated (Affiliated) Companies

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

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2		IGC/MDU/MDU RESOURCES	107	2,130,631
3			426.1	211,302
4			426.2	(569,914)
5			426.4	306,254
6			426.5	1,556
7			813	172,370
8			870	1,236,084
9			874	465,129
10			875	115,170
11			878	
12			880	1,235,529
13			881	69,876
14			885	80,218
15			887	619,344
16			887.1	7,141
17			892	200
18			894	48,297
19			901	44,898
20	Goods or Services Provided for Affiliated Company			
21			902	211,446
22			903	5,336,032
23			904	1,209,258
24			908	279,237
25			909	166,830
26			920	7,255,805
27			921	3,391,431
28			922	(245,018)
29			923	267,373
30			925	9,351
31			926	28,351
32			930.1	30,962
33			930.2	753,502
34			931	1,384,279
35			932	2,101
36			Various	
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 storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.
2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned.

Line No.	Name of Station and Location (a)	Number of Units at Station (b)	Certificated Horsepower for Each Station (c)	Plant Cost (d)
1	Compressor Station at Burlington, WA	1	1,350	2,000,731
2	Placed in Service: August 2001			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

Compressor Stations

Designate any station that was not operated during the past year. State in a footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are contemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year and show in a footnote each unit's size and the date the unit was placed in operation.

3. For column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or power.

Line No.	Expenses (except depreciation and taxes) Fuel (e)	Expenses (except depreciation and taxes) Power (f)	Expenses (except depreciation and taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station in kWh (i)	Operational Data Total Compressor Hours of Operation During Year (j)	Operational Data Number of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1	4,926		126,657				1	
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
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Gas Storage Projects

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January			
3	February			
4	March			
5	April			
6	May			
7	June			
8	July			
9	August			
10	September			
11	October			
12	November			
13	December			
14	TOTAL (Total of lines 2 thru 13)			
15	Gas Withdrawn from Storage			
16	January			
17	February			
18	March			
19	April			
20	May			
21	June			
22	July			
23	August			
24	September			
25	October			
26	November			
27	December			
28	TOTAL (Total of lines 16 thru 27)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	
2	Cushion Gas (Including Native Gas)	
3	Total Gas in Reservoir (Total of line 1 and 2)	
4	Certificated Storage Capacity	
5	Number of Injection - Withdrawal Wells	
6	Number of Observation Wells	
7	Maximum Days' Withdrawal from Storage	
8	Date of Maximum Days' Withdrawal	
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	LNG Volume	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Transmission Lines

1. Report below, by state, the total miles of transmission lines of each transmission system operated by respondent at end of year.
2. Report separately any lines held under a title other than full ownership. Designate such lines with an asterisk, in column (b) and in a footnote state the name of owner, or co-owner, nature of respondent's title, and percent ownership if jointly owned.
3. Report separately any line that was not operated during the past year. Enter in a footnote the details and state whether the book cost of such a line, or any portion thereof, has been retired in the books of account, or what disposition of the line and its book costs are contemplated.
4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
1	None		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
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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 12 months embracing the heating season overlapping the year's end for which this report is submitted. The season's peak normally will be reached before the due date of this report, April 30, which permits inclusion of the peak information required on this page. Add rows as necessary to report all data. Number additional rows 6.01, 6.02, etc.

Line No.	Description	Dth of Gas Delivered to Interstate Pipelines (b)	Dth of Gas Delivered to Others (c)	Total (b) + (c) (d)
	SECTION A: SINGLE DAY PEAK DELIVERIES			
1	Date:			
2	Volumes of Gas Transported			
3	No-Notice Transportation			
4	Other Firm Transportation			
5	Interruptible Transportation			
6	Other (Describe) (footnote details)			
7	TOTAL			
8	Volumes of gas Withdrawn form Storage under Storage Contract			
9	No-Notice Storage			
10	Other Firm Storage			
11	Interruptible Storage			
12	Other (Describe) (footnote details)			
13	TOTAL			
14	Other Operational Activities			
15	Gas Withdrawn from Storage for System Operations			
16	Reduction in Line Pack			
17	Other (Describe) (footnote details)			
18	TOTAL			
19	SECTION B: CONSECUTIVE THREE-DAY PEAK DELIVERIES			
20	Dates:			
21	Volumes of Gas Transported			
22	No-Notice Transportation			
23	Other Firm Transportation			
24	Interruptible Transportation			
25	Other (Describe) (footnote details)			
26	TOTAL			
27	Volumes of Gas Withdrawn from Storage under Storage Contract			
28	No-Notice Storage			
29	Other Firm Storage			
30	Interruptible Storage			
31	Other (Describe) (footnote details)			
32	TOTAL			
33	Other Operational Activities			
34	Gas Withdrawn from Storage for System Operations			
35	Reduction in Line Pack			
36	Other (Describe) (footnote details)			
37	TOTAL			

Auxiliary Peaking Facilities

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

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

Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales,transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

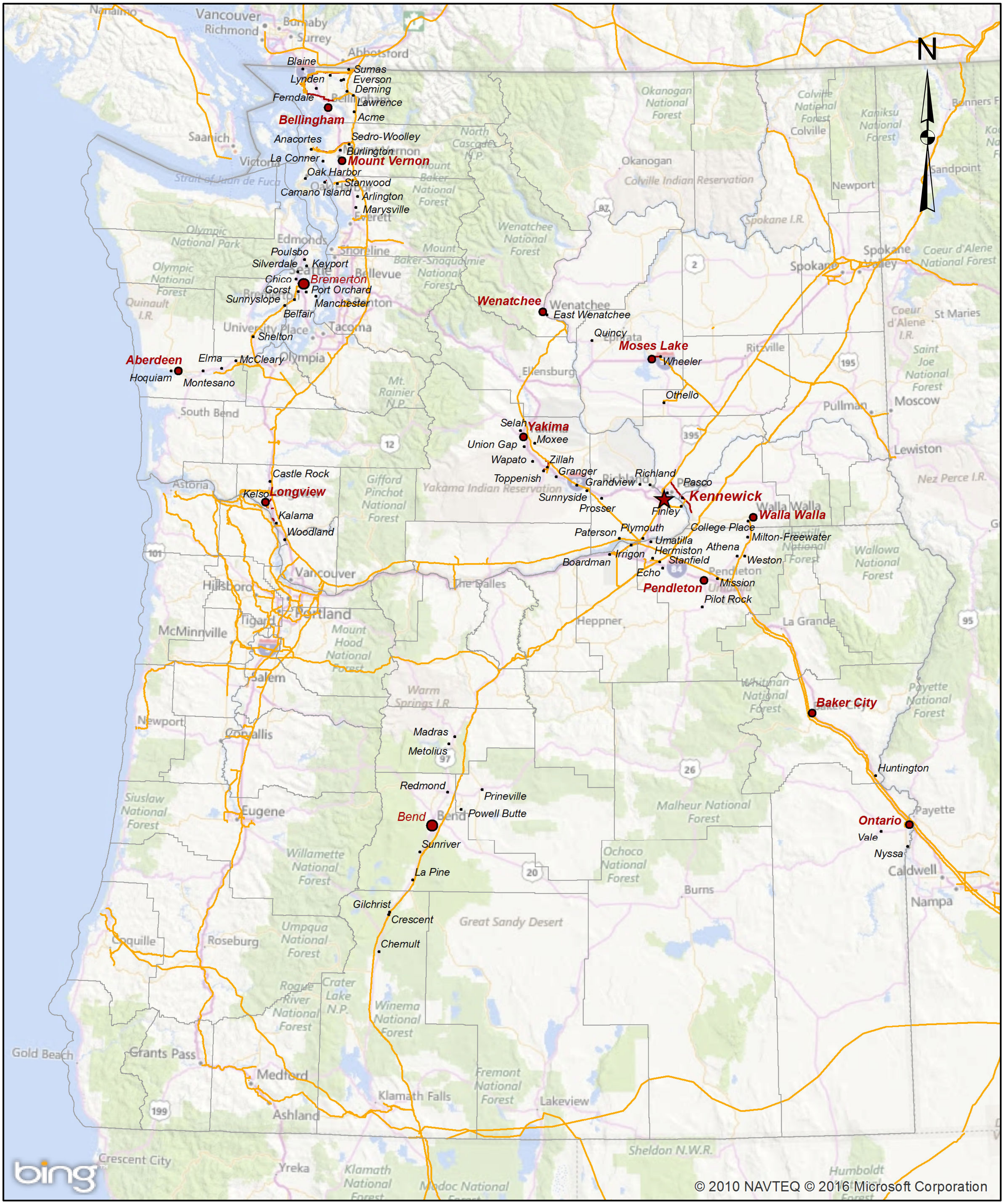
Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
01	Name of System:			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		36,145,294	
4	Gas of Others Received for Gathering (Account 489.1)	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)		2,325,380	
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)		108,892,465	
16	Total Receipts (Total of lines 3 thru 15)		147,363,139	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		35,356,500	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	108,892,465	
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)		2,376,972	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		37,100	
30	Total Deliveries (Total of lines 18 thru 29)		146,663,037	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		700,102	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		147,363,139	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2019	2019/Q4

System Maps

1. Furnish five copies of a system map (one with each filed copy of this report) of the facilities operated by the respondent for the production, gathering, transportation, and sale of natural gas. New maps need not be furnished if no important change has occurred in the facilities operated by the respondent since the date of the maps furnished with a previous year's annual report. If, however, maps are not furnished for this reason, reference should be made in the space below to the year's annual report with which the maps were furnished.
2. Indicate the following information on the maps:
   (a) Transmission lines.
   (b) Incremental facilities.
   (c) Location of gathering areas.
   (d) Location of zones and rate areas.
   (e) Location of storage fields.
   (f) Location of natural gas fields.
   (g) Location of compressor stations.
   (h) Normal direction of gas flow (indicated by arrows).
   (i) Size of pipe.
   (j) Location of products extraction plants, stabilization plants, purification plants, recycling areas, etc.
   (k) Principal communities receiving service through the respondent's pipeline.
3. In addition, show on each map: graphic scale of the map; date of the facts the map purports to show; a legend giving all symbols and abbreviations used; designations of facilities leased to or from another company, giving name of such other company.
4. Maps not larger than 24 inches square are desired. If necessary, however, submit larger maps to show essential information. Fold the maps to a size not larger then this report. Bind the maps to the report.

See attached map.



CASCADE NATURAL GAS CORPORATION®
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

Communities Served

Communities
- Community Served
- District Office
- Region Office
- General Office

Document Path: G:\Dept\Mapping\SYSTEM MAP\System Map.mxd /Date: 3/11/2016

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) __ A Resubmission	12/31/2019	2019/Q4

System Maps

1. Furnish five copies of a system map (one with each filed copy of this report) of the facilities operated by the respondent for the production, gathering, transportation, and sale of natural gas. New maps need not be furnished if no important change has occurred in the facilities operated by the respondent since the date of the maps furnished with a previous year's annual report. If, however, maps are not furnished for this reason, reference should be made in the space below to the year's annual report with which the maps were furnished.
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   (a) Transmission lines.
   (b) Incremental facilities.
   (c) Location of gathering areas.
   (d) Location of zones and rate areas.
   (e) Location of storage fields.
   (f) Location of natural gas fields.
   (g) Location of compressor stations.
   (h) Normal direction of gas flow (indicated by arrows).
   (i) Size of pipe.
   (j) Location of products extraction plants, stabilization plants, purification plants, recycling areas, etc.
   (k) Principal communities receiving service through the respondent's pipeline.
3. In addition, show on each map: graphic scale of the map; date of the facts the map purports to show; a legend giving all symbols and abbreviations used; designations of facilities leased to or from another company, giving name of such other company.
4. Maps not larger than 24 inches square are desired. If necessary, however, submit larger maps to show essential information. Fold the maps to a size not larger then this report. Bind the maps to the report.

See attached map.

Schedule Page: 234 Line No.: 3 Column: g

Regulatory accounts related to Pension and Customer Advances

Schedule Page: 234 Line No.: 3 Column: i

Regulatory accounts related to Pension and Customer Advances

Schedule Page: 260 Line No.: 8 Column: a

The loss associated with each reacquisition consists of a reacquisition premium, other reacquisition expenses, and remaining unamortized issuance costs (Account 181) at the time of reacquisition.

(1) 7.5% Notes were reacquired in March 2007 and refunded by 5.79% Senior Notes for $40,000,000 due 3/08/2037. The remaining unamortized debt expense of $1,229,120 was reclassified to unamortized loss on reacquired debt.

Schedule Page: 261 Line No.: 7 Column: a

SFAS No.87 pension plan accural	120,478
Interest capitalized adj (IRS>books)	359,103
263A Adjustment - UNICAP	1,410
Total	**480,991**

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

Tax Expense	169,039
Depreciation provision	33,897,395
Vacation Accrual - current year	1,903,016
Incentive accrual	1,696,506
Bad Debt Expense	1,209,258
Prepaids	375,930
Qualified Transporation Fringe	2,670
AFUDC Equity	105
Lobbying (5912.4264)	306,253
50% of businiess meals & entertainment	162,777
Payroll Taxes - Incentive accrual	56,523
Amort of loss on reacquired debt (4281)	40,971
100% of business entertainment	8,201
Penalties (5984)	50
Interest Expense	3,227
Total	**39,831,921**

Schedule Page: 261 Line No.: 15 Column: a

Tax Gain (loss) on disposal of assets	(3,231,959)
Bellingham, Bremerton, & Eugene MGP expenses	(518,600)
Retiree Medical Accrual	(58,605)
Performance Share Perm	(526,635)
Total	**(4,335,799)**

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

Depreciation & amortization of plant	(38,966,039)
Deferred Gas Costs	(47,723,076)
Conservation Program	(495,644)
MAOP Deferred Costs WA/OR	(1,905,558)
Repairs Deduction	(5,252,568)
Vacation accrual - prior year	(1,949,322)
SFAS No.87 accrual-SERP/SISP add back bk expense	(40,723)
Bad debts written off	(1,156,825)
SERP/SISP-perm difference piece	(1,705,005)
Reserved Revenue	(348,812)
Prepaid Expenses	(486,786)
Incentive accrual - prior year	(981,906)
401K Dividends (MDUR)	(209,490)
Customer Advances - 2520.000 to 2520.2991	(92,058)
Legal Reserve	(29,318)
Royalty Income (15% of royalty income receipts)	(1,153)
Oregon State Income Tax	794,016
Total	**(100,550,267)**

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

Difference between 12/31/18 accrual and tax return	(1,843,703)

FOOTNOTE DATA

R&D tax credits	(145,000)
FIN48 - R&D tax credits	29,000
Total	**(1,959,703)**

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

Allocated to:	409.1	409.2	Total
Washington	(10,887,316)	616,283	(10,271,033)
Oregon	(638,182)	(29,140)	(667,322)
Total	**(11,525,498)**	**587,143**	**(10,938,355)**

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

Taxable Income for Federal Tax	(42,755,488)
Oregon adjustments to Federal Taxable Income:	
Oregon State Income Tax expense deducted from Federal Return	(794,016)
Bonus Depreciation adjustment	(443,431)
Taxable Income for Oregon Tax	(43,992,935)
Oregon Apportionment Factor	23.7483%
Oregon Taxable Income	(10,447,574)
Oregon Tax Rate	7.60%
Estimated Tax Return Oregon Income Tax	(794,016)
Adjustments:	
Difference between 12/31/18 accrual and tax return	(236,465)
Provision for Current Oregon Income Tax	**(1,030,481)**

Allocated to:	409.1	409.2	Total
Total	**(941,388)**	**(89,093)**	**(1,030,481)**

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

Regulatory accounts related to FAS158 and deferred tax effect of Oregon State Tax Rate Increase.

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

Regulatory accounts related to FAS158 and deferred tax effect of Oregon State Tax Rate Increase.

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

Depreciation is accrued monthly on the average balance in each plant account using a rate specific to the account. The average balance is the simple average of the balance at the beginning of the month and at the end of the month. The amounts shown below represent the year-end balances of depreciable plant and the weighted average composite rates based on year-end balances in each category.

	Washington		Oregon	
Description (a)	Depreciable Plant Base (Thousands) (b)	Composite Rate (Percent) (c)	Depreciable Plant Base (Thousands) (d)	Composite Rate (Percent) (e)
Intangible plant	32,472		12,479	
Manufactured gas production	0		0	
Transmission plant	17,063	1.80%	6,247	1.81%
Distribution plant	752,013	2.79%	215,875	2.96%
General plant	51,126	3.92%	17,852	3.85%
Total	**852,674**	**3.03%**	**252,453**	**3.20%**

Schedule Page: 354 Line No.: 75 Column: a

PTO/Incentive/Severance Pay Liabilites $1,697,135

INDEX

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)

SUPPLEMENTAL REPORT TO

OREGON PUBLIC UTILITY COMMISSION

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Cascade Natural Gas Corporation	End of 2019/Q4

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2019

INDEX

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	GAS UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	67,070,587	62,341,032
3	Operating Expenses			
4	Operation Expenses (401)	4-9	45,189,208	42,747,407
5	Maintenance Expenses (402)	4-9	1,534,085	1,738,467
6	Depreciation Expense (403)	10	6,881,592	6,154,978
7	Amortization & Depletion of Utility Plant (404-405)	10	891,397	909,516
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	5,734,175	5,105,787
12	Income Taxes - Federal (409.1)	12	(638,182)	477,754
13	Income Taxes - Other (409.1)	13	(941,388)	(461,582)
14	Provision for Deferred Income Taxes (410.1)	14-21	12,811,911	2,444,547
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	(11,030,657)	(2,356,657)
16	Investment Tax Credit Adjustment - Net (411.4)	22	(10,278)	(9,690)
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)		60,421,863	56,750,527
20	Net Utility Operating Income (Enter Total of line 2 less 19)		6,648,724	5,590,505

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - GAS OPERATING REVENUES (ACCOUNT 400)

Line No.	ACCOUNT (a)	OPERATING REVENUES CURRENT YEAR (b)	OPERATING REVENUES PREVIOUS YEAR (c)	MCF OF NATURAL GAS SOLD CURRENT YEAR (d)	MCF OF NATURAL GAS SOLD PREVIOUS YEAR (e)	AVG. NO. OF NAT. GAS CUSTUMERS PER MO. CURRENT YEAR (f)	AVG. NO. OF NAT. GAS CUSTUMERS PER MO. PREVIOUS YEAR (g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	$ 37,648,100	$ 35,735,954	4,631,397	4,078,092	65,860	64,137
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 21,011,593	$ 19,735,290	3,192,406	2,836,254	10,144	10,061
5	Large or Industrial	$ 4,009,032	$ 4,064,217	710,667	671,341	161	157
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 62,668,725	$ 59,535,461	8,534,470	7,585,687	76,165	74,355
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 62,668,725	$ 59,535,461	8,534,470	7,585,687	76,165	74,355
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 62,668,725	$ 59,535,461				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 169,984	$ 146,470				
17	489 Revenue from Trans. of Gas of Others	$ 4,432,276	$ 4,125,680				
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	$ 11,000				
22	494 Interdepartmental Rents	$ 42,263	$ 28,749				
23	495 Other Gas Revenues	$ 13,492	$ 51,692				
24	TOTAL Other Operating Revenues	$ 4,670,015	$ 4,363,591				
25	TOTAL Gas Operating Revenues	$ 67,338,740	$ 63,899,052				
26	(Less) 496 Provision for Rate Refunds	$ (268,153)	$ (1,558,020)				
27	TOTAL Gas Operating Revenues Net of Provision for Refunds						
28	Dist. Type Sales by States (*Incl. Main Line Sales to Residential and Commercial Customers)*	$ 58,659,693		7,823,803			
29	Main Line Industrial Sales *(Incl. Main Line Sales to Public Authorities)*	$ 4,009,032		710,667			
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))*	$ 62,668,725		8,534,470			

NOTES:

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

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

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

LINE NO.	NAME OF LESSEE OR DEPARTMENT (Designate associated companies) (a)	DESCRIPTION OF PROPERTY (b)	AMOUNT OF REVENUE FOR YEAR: NATURAL GAS PROPERTY (c)	AMOUNT OF REVENUE FOR YEAR: MANUFACTURED GAS PROPERTY (d)
	Account 493			
	Stone Bros., Inc.	Northern portion of parking lot at the Hermiston office for a latte stand.	$ 12,000	
			$ -	
			$ -	
	Total Account 493		$ 12,000	

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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

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CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
	B2. Products Extraction (Con't)		
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Reg. Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	Total Maintenance (Enter Total of lines 49 thru 56)	0	0
58	Total Products Extraction (Enter Total of lines 47 and 57)	0	0
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	Total Exploration & Development (Enter Total of lines 61 thru 64)	0	0
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases	0	0
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
69	801 Natural Gas Field Line Purchases	0	0
70	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
71	803 Natural Gas Transmission Line Purchases	0	0
72	804 Natural Gas City Gate Purchases	38,267,373	32,942,897
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	(7,645,455)	(3,808,349)
76	805.2 Incremental Gas Cost Adjustments	0	0
77	Total Purchased Gas (Enter Total of lines 67 to 75)	30,621,918	29,134,548
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	882,304	506,266
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	(15,089)	(10,870)
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(15,089)	(10,870)
95	813 Other Gas Supply Expenses	110,977	88,245
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	31,600,110	29,718,189
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	31,600,110	29,718,189

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
98	2. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	Total Operation (Enter Total of lines 101 thru 113)	0	0
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	Total Maintenance (Enter Total of lines 116 thru 123)	0	0
125	Total Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	Total Operation (Enter Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures and Improvements	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	Total Maintenance (Enter Total of lines 136 thru 144)	0	0
146	Total Other Storage Expenses (Enter Total of lines 134 and 145)	0	0

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

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulation Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(Less) 845.5 Wharfage Receipts - Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	Total Operation (Enter Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	Total Maintenance (Enter Total of lines 167 thru 174)	0	0
176	Total Liquefied Nat Gas Terminaling & Process Exp (Lines 165 & 175)	0	0
177	Total Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	Total Operation (Enter Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Reg. Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	Total Maintenance (Enter Total of lines 193 thru 199)	0	0
201	Total Transmission Expenses (Enter Total of lines 191 and 200)	0	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

LINE NO.	ACCOUNT (a)	CUURENT YEAR (b)	PREVIOUS YEAR (c)
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	857,539	826,122
205	871 Distribution Load Dispatching	93,055	85,199
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,392,379	1,282,991
209	875 Measuring and Regulating Station Expenses - General	167,374	176,642
210	876 Measuring and Regulating Station Expenses - Industrial	30,552	38,171
211	877 Measuring & Regulating Station Exp - City Gate Check Station	0	0
212	878 Meter and House Regulator Expenses	212,192	231,859
213	879 Customer Installations Expenses	221,585	241,652
214	880 Other Expenses	2,127,507	1,884,697
215	881 Rents	25,710	28,789
216	Total Operation (Enter Total of lines 204 thru 215)	5,127,893	4,796,122
217	Maintenance		
218	885 Maintenance Supervision and Engineering	241,936	221,877
219	886 Maintenance of Structures and Improvements	0	441
220	887 Maintenance of Mains	259,335	415,071
221	888 Maintenance of Compressor Station Equipment	21	227
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	64,133	69,974
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	18,132	5,266
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	0
225	892 Maintenance of Services	293,453	408,632
226	893 Maintenance of Meters and House Regulators	252,112	251,250
227	894 Maintenance of Other Equipment	394,676	357,562
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,523,798	1,730,300
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	6,651,691	6,526,422
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	36,248	35,776
233	902 Meter Reading Expenses	225,211	219,001
234	903 Customer Records and Collection Expenses	1,397,978	1,404,414
235	904 Uncollectible Accounts	215,040	171,038
236	905 Miscellaneous Customer Accounts Expenses	32,728	2
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,907,205	1,830,231
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	166,899	208,213
242	909 Informational and Instructional Expenses	51,851	2,983
243	910 Miscellaneous Customer Service and Informational Expenses	89,173	86,177
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	307,923	297,373
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	1,051	0
249	913 Advertising Expenses	1,023	1,293
250	916 Miscellaneous Sales Expenses	0	0
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	2,074	1,293

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

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	2,186,116	1,882,113
255	921 Office Supplies and Expenses	1,125,495	1,057,859
256	(Less) 922 Administrative Expenses Transferred - Cr.	(104,567)	(101,231)
257	923 Outside Services Employed	188,361	577,828
258	924 Property Insurance	27,405	20,620
259	925 Injuries and Damages	334,701	465,943
260	926 Employee Pensions and Benefits	1,753,413	1,492,230
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	100,603	0
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	9,597	8,194
265	930.2 Miscellaneous General Expenses	250,751	297,496
266	931 Rents	372,128	403,147
267	Total Operation (Enter Total lines 254 thru 266)	6,244,003	6,104,199
268	Maintenance		
269	935 Maintenance of General Plant	10,287	8,167
270	Total Administrative and General Exp (Total of lines 267 and 269)	6,254,290	6,112,366
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	46,723,293	44,485,874

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	31,600,110	0	31,600,110
280	Total Production	31,600,110	0	31,600,110
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	5,127,893	1,523,798	6,651,691
286	Customer Accounts Expenses	1,907,205	0	1,907,205
287	Customer Service and Informational Expenses	307,923	0	307,923
288	Sales Expenses	2,074	0	2,074
289	Admin and General Expenses	6,244,003	10,287	6,254,290
290	Total Gas O. & M. Expenses	45,189,208	1,534,085	46,723,293

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURALGAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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			891,397			891,397
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	6,396,479					6,396,479
10	General Plant	371,940					371,940
11	Common Plant - Gas	[redacted]					-
12							
13							
14							
15							
16							
17							
18							
19	**TOTAL**	**6,881,592**	**-**	**891,397**	**-**	**-**	**7,772,989**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,829,815
2	Payroll Taxes	605,206
3	Oregon PUC Regulatory Fee	187,024
4	Oregon Department of Energy Fee	78,672
5	City Franchise Taxes	2,996,281
6	Miscellaneous Taxes	37,177
	TOTAL (Must agree with page 1, line 11)	**5,734,175**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

Line No.	PARTICULARTS (Details) (a)				Amount (b)
1	Gas Operating Revenues				157,740,604
2	Operations and Maintenance Expenses				(68,089,710)
3	Taxes, Other than Income				(30,542,472)
4	State Income (Excise) Tax				794,015
5	Interest				(15,173,527)
6	Other Income				5,250,296
7	Federal Income Tax Depreciation				(38,551,269)
8	Other Additions (Subtractions) to Derive Taxable Income				
9	AFUDC-Debt/Equity				(649,190)
10	Capitalized Tax Interest				1,008,398
11	CIAC				1,031,570
12	Customer Advances				(92,058)
13	Loss on Disposal of Assets				(3,231,959)
14	Amort of loss on reacquired debt				40,971
15	Bad Debts				52,433
16	Legal Reserve				(29,318)
17	Pension & Post Retirement				61,873
18	Prepaid Expenses				(110,856)
19	Reserved Revenue				(348,812)
20	SISP/SERP				(40,723)
21	STIP Payroll Taxes				771,124
22	Vacation Pay				(46,306)
23	50% of Meals & Entertainment				162,778
24	Other Permanent Differences				12,995
25	Lobbying Expenses				306,254
26	Manufactured Gas Plant Cleanup				(518,600)
27	MAOP Deferred Costs				(1,905,558)
28	Conservation Programs				(495,644)
29	Purchased Gas Adjustment				(47,723,076)
30	UNICAP				1,410
31	401k Dividends				(209,490)
32	SISP/SERP Premium & CSV				(1,705,005)
33	Performance Shares				(526,635)
34	Federal Tax Net Income				(42,755,487)
35	Show Computation of Tax:				
36	Federal Tax Rate				21%
37	Estimated Federal Tax				(8,978,652)
38	Adjustments to Estimated Federal Tax				
39	Difference between 12/31/18 accrual and tax return				(1,843,703)
40	R&D credit				(145,000)
41	FIN 48 Adjustment				29,000
42	Provision for Current Federal Income Tax			409.1	(10,938,355)
43					
44					
45	Allocated to:	409.1	409.2		Total
46	Washington	(10,887,316)	616,283		(10,271,033)
47	Oregon	(638,182)	(29,140)		(667,322)
48	Total	(11,525,498)	587,143		(10,938,355)
49					
50					
51					
52					
53					
54					
55					

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, 2019

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

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

Line No.	Particularts (Details) (a)			Amount (b)
1	Gas Operating Revenues			157,740,604
2	Operations and Maintenance Expenses			(68,089,710)
3	Taxes, Other than Income			(30,542,472)
4	State Income (Excise) Tax			
5	Interest			(15,173,527)
6	Other Income			5,250,296
7	Federal Income Tax Depreciation			(38,551,269)
8	Other Additions (Subtractions) to Derive Taxable Income			
9	AFUDC-Debt/Equity			(649,190)
10	Capitalized Tax Interest			1,008,398
11	CIAC			1,031,570
12	Customer Advances			(92,058)
13	Loss on Disposal of Assets			(3,231,959)
14	Amort of loss on reacquired debt			40,971
15	Bad Debts			52,433
16	Legal Reserve			(29,318)
17	Pension & Post Retirement			61,873
18	Prepaid Expenses			(110,856)
19	Reserved Revenue			(348,812)
20	SISP/SERP			(40,723)
21	STIP Payroll Taxes			771,124
22	Vacation Pay			(46,306)
23	50% of Meals & Entertainment			162,778
24	Other Permanent Differences			12,995
25	Lobbying Expenses			306,254
26	Manufactured Gas Plant Cleanup			(518,600)
27	MAOP Deferred Costs			(1,905,558)
28	Conservation Programs			(495,644)
29	Purchased Gas Adjustment			(47,723,076)
30	UNICAP			1,410
31	401k Dividends			(209,490)
32	SISP/SERP Premium & CSV			(1,705,005)
33	Performance Shares			(526,635)
34	OR Bonus Depreciation			(443,431)
35	Federal Tax Net Income			(43,992,933)
36	Oregon Apportionment Rate			23.7483%
37	State Tax Net Income			(10,447,574)
38	Show Computation of Tax:			
39	State Tax Rate			7.6%
40				(794,016)
41	Adjustments to Estimated State Tax			
42	Difference between 12/31/18 accrual and tax return			(236,465)
43	Provision for Current Federal Income Tax			(1,030,481)
44				
45				
46	Allocated to:	409.1	409.2	Total
47		(941,388)	(89,093)	(1,030,481)
48				
49				
50				
51				
52				
53				
54				
55				

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, 2019**

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	17,102,003	(12,657,011)	11,570,300
6				
7	Other	-		
8	TOTAL GAS	17,102,003	(12,657,011)	11,570,300
9	Other (Specify)	-		
10	TOTAL (Account 190)	17,102,003	(12,657,011)	11,570,300
11	Classification of Totals			
12	Federal Income Tax	15,725,604	(11,672,828)	10,669,511
13	State Income Tax	1,376,399	(984,183)	900,789
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	12,147,162	(8,333,419)	7,631,472
18	Federal Income Tax - Oregon	3,578,442	(3,339,409)	3,038,039
19	State Income Tax - Oregon	1,376,399	(984,183)	900,789
20				
21				
22				

NAME OF RESPONDENT **CASCADE NATURAL GAS COPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2019**

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
(762,822)	59,042	Regulatory accounts related to FAS 158 and OR rate change adjustments	1,019,871	Regulatory accounts related to FAS 158 and OR rate change adjustments	(8,179,495)	8,151,888	5
							6
						-	7
(762,822)	59,042		1,019,871		(8,179,495)	8,151,888	8
						-	9
(762,822)	59,042		1,019,871		(8,179,495)	8,151,888	10
							11
(702,510)	55,372		1,007,569		(7,586,907)	7,495,811	12
(60,312)	3,670		12,302		(592,588)	656,077	13
-	-		-		-	-	14
							15
							16
(528,077)	41,623		892,051		(5,807,667)	6,043,145	17
(174,433)	13,749		115,518		(1,779,240)	1,452,666	18
(60,312)	3,670		12,302		(592,588)	656,077	19
							20
							21
							22

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR 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) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2019

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

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	(53,594,339)	(4,691,709)	2,939,172
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(53,594,339)	(4,691,709)	2,939,172
6	Other (Specify)			
7				
8				
9	Total (Account 282) Lines 5 thru 8	(53,594,339)	(4,691,709)	2,939,172
10	Classification of Totals			
11	Federal Income Tax	(49,763,427)	(4,173,671)	2,778,836
12	State Income Tax	(3,830,912)	(518,038)	160,336
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	(38,463,931)	(3,463,972)	2,131,944
	Federal Income Tax - Oregon	(11,299,496)	(709,699)	646,892
	State Income Tax - Oregon	(3,830,912)	(518,038)	160,336

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS		CREDITS			
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	182.3 & 254	102,647,993	182.3 & 254	(105,168,567)	(57,867,450)	3
						-	4
-	-		102,647,993		(105,168,567)	(57,867,450)	5
						-	6
							7
							8
-	-		102,647,993		(105,168,567)	(57,867,450)	9
							10
-	-	254	102,570,773	254	(105,096,084)	(53,683,573)	11
-	-	182.3	77,220	182.3	(72,483)	(4,183,877)	12
-	-		-		-	-	13
-	-		79,481,537		(81,438,787)	(41,753,209)	
-	-		23,089,236		(23,657,297)	(11,930,364)	
-	-		77,220		(72,483)	(4,183,877)	

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	(34,901,601)	(27,691,005)	19,054,142
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(34,901,601)	(27,691,005)	19,054,142
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(34,901,601)	(27,691,005)	19,054,142
10	Classification of Totals			
11	Federal Income Tax	(31,839,495)	(25,500,861)	17,658,724
12	State Income Tax	(3,062,106)	(2,190,144)	1,395,418
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	(26,957,638)	(20,430,423)	12,769,540
	Federal Income Tax - Oregon	(4,881,857)	(5,070,438)	4,889,184
	State Income Tax - Oregon	(3,062,106)	(2,190,144)	1,395,418

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited Account 410.2	Amounts Credited Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	7,699,041	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	(1,630,337)	(37,469,760)	3
						-	4
-	-		7,699,041		(1,630,337)	(37,469,760)	5
						-	6
							7
							8
-	-		7,699,041		(1,630,337)	(37,469,760)	9
							10
-	-		7,080,815		(1,600,148)	(34,200,965)	11
-	-		618,226		(30,189)	(3,268,795)	12
-	-		-		-	-	13
-	-		5,274,665		(1,161,008)	(30,504,864)	
-	-		1,806,150		(439,140)	(3,696,101)	
-	-		618,226		(30,189)	(3,268,795)	

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

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

Line No.	Account Subdivision	Balance at Beginning of Year	Deferred For Year		Allocations to Current Year's Income		Adjustments	Balance at End of Year	Average period of Allocation to Income
			Account No	Amount	Account No	Amount			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(10,278)		ALLOCATED	23 Years
6	Total	0		0		(10,278)			
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									
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23									
24									
25									

NOTES

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT		YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)		**Dec. 31, 2019**

STATE OF OREGON - SITUS UTILITY PLANT

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	233,716,290		233,716,290			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	11,359,613		11,359,613			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	245,075,903	-	245,075,903	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,697,915		1,697,915			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	246,773,818	-	246,773,818	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(102,609,519)		(102,609,519)			
15	Net Utility Plant (Line 13 less 14)	144,164,299	-	144,164,299	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(102,443,629)		(102,443,629)			
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	(165,890)		(165,890)			
22	Total In-Service (Total of lines 18 thru 21)	(102,609,519)	-	(102,609,519)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and depletion	-		-			
26	Total leased to others (Total of lines 24 and 25)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization	-		-			
30	Total Held for Future Use (Total of lines 28 & 29)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (lines 22,26, 30, 31 & 32)	(102,609,519)	-	(102,609,519)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant In Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction not Classified.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts on an estimated basis if necessary, and include entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year. **(Continue on page 25)**

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
1		1. Intangible Plant						
2	301	Organization						
3	302	Franchises and Consents	73,667					73,667
4	303	Miscellaneous Intangible Plant	2,947,821					2,947,821
5		TOTAL Intangible Plant	3,021,488	-	-	-	-	3,021,488
6		2. Production Plant						
7		Natural Gas Production & Gathering Plant						
8	325.1	Producing Lands	-					-
9	325.2	Producing leaseholds	-					-
10	325.3	Gas Rights	-					-
11	325.4	Rights-of-Way	-					-
12	325.5	Other Land and Land Rights	-					-
13	326	Gas Well Structures	-					-
14	327	Field Compressor Station Structures	-					-
15	328	Field Measuring and Regulating Station Structures	-					-
16	329	Other Structures	-					-
17	330	Producing Gas Wells- Well Construction	-					-
18	331	Producing Gas Wells- Well Equipment	-					-
19	332	Field Lines	-					-
20	333	Field Compressor Station Equipment	-					-
21	334	Field Measuring and Regulating Station Equipment	-					-
22	335	Drilling and Cleaning Equipment	-					-
23	336	Purification Equipment	-					-
24	337	Other Equipment	-					-
25	338	Unsuccessful Exploration & Development Costs	-					-
26		TOTAL Production & Gathering Plant	-	-	-	-	-	-
27		Products Extraction Plant						
28	340	Land and Land Rights	-					-
29	341	Structures and Improvements	-					-
30	342	Extraction and Refining Equipmnet	-					-
31	343	Pipe Lines	-					-
32	344	Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initally recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing sub-account classification of such plant conforming to the requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2019**

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

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		TOTAL Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	13,131					13,131
80	365.2	Rights of Way	7,693					7,693
81	366	Structures and Improvements	-					-
82	367	Mains	5,818,920					5,818,920
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	36,162					36,162
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
86.a	372	ARO - Transmission	24,893		(304)			24,589
87		TOTAL Transmission Plant	5,900,799	-	(304)	-	-	5,900,495
88		5. Distribution Plant						
89	374	Land and Land Rights	377,949	(1,069)				376,880
90	375	Structures and Improvements	363,785					363,785
91	376	Mains	101,680,212	10,421,394	(93,476)			112,008,130
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	10,605,834	592,381	(74,427)			11,123,788
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	56,284,950	4,540,371	(53,263)			60,772,058
96	381	Meters	16,586,725	1,896,955	(1,901,719)	123,539		16,705,500
97	382	Meter Installations	9,659,588	77,983	(4,991)	(15,118)		9,717,462
98	383	House Regulators	2,847,027	192,129	(99,781)	21,205		2,960,580
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	2,199,898	263,850	(36,922)	15,118		2,441,944
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,827,543	880,729	(8,478)			5,699,794
103		TOTAL Distribution Plant	205,433,511	18,864,723	(2,273,057)	144,744	-	222,169,921

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, 2019**

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	4,516,175	604				4,516,779
107	391	Office Furniture and Equipment	178,477					178,477
108	392	Transportation Equipment	3,752,149	632,826	(66,417)			4,318,558
109	393	Stores Equipment	-					-
110	394	Tools, Shop and Garage Equipment	1,518,442	58,574	(21,087)			1,555,929
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	1,224,525	857,085	(773,605)	1		1,308,006
113	397	Communication Equipment	1,605,741	(1)				1,605,740
114	398	Miscellaneous Equipment	7,209					7,209
115		SUBTOTAL	13,296,019	1,549,088	(861,109)	1	-	13,983,999
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	13,296,019	1,549,088	(861,109)	1	-	13,983,999
118		TOTAL (Accounts 101 and 106)	227,651,817	20,413,811	(3,134,470)	144,745	-	245,075,903
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	227,651,817	20,413,811	(3,134,470)	144,745	-	245,075,903

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, 2019

STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Acct. (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
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3				
4				
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52	TOTALS-	0	0	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	Replace 12" HP main in Bend, OR (Phase 2)	726,190	
2	Install main to Pacific Cascade Heights in Bend, OR	631,656	
3			
4			
5			
6	Minor installation of mains, service lines, measuring and regulating stations,	340,069	
7	meter sets and telemetering, and etc.		
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43	T O T A L -	1,697,915	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	(98,236,122)	(98,236,122)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(6,682,883)	(6,682,883)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(287,417)	(287,417)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(68,411)	(68,411)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(7,038,711)	(7,038,711)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	3,134,466	3,134,466		
12	Cost of Removal	392,971	392,971		
13	Salvage (credits)	(732,098)	(732,098)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	2,795,339	2,795,339		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	60,927	60,927		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(25,062)	(25,062)		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(102,443,629)	(102,443,629)		
	Section B. Balances at End of Year According to Functional Classifications				
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	(3,742,151)	(3,742,151)		
25	Distribution	(94,984,595)	(94,984,595)		
26	General	(4,169,602)	(4,169,602)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	526,386	526,386		
27	TOTAL (*Enter Total of Lines 18 thru 26*)	(102,443,629)	(102,443,629)		

NOTE:

Row 15.02 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT		YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)		**Dec. 31, 2019**

STATE OF OREGON - ALLOCATED

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	15,528,343		15,528,343			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	(331,367)		(331,367)			
7	Experimental Plant Unclassified	-					
8	TOTAL (*Enter Total of lines 3 thru 7*)	15,196,976	-	15,196,976	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	387,387		387,387			
12	Acquisition Adjustments	-					
13	Total Utility Plant (*Lines 8 thru 12*)	15,584,363	-	15,584,363	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(7,806,822)		(7,806,822)			
15	Net Utility Plant (Line 13 less 14)	7,777,541	-	7,777,541	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(2,777,228)		(2,777,228)			
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	(5,029,594)		(5,029,594)			
22	Total In-Service (*Lines 18 thru 21*)	(7,806,822)	-	(7,806,822)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and Depletion	-		-			
26	Total Leased to Others (*Lines 24 and 25*)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization and Depletion	-		-			
30	Total Leased to Others (*Lines 28 and 29*)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (*lines 22, 26, 30, 31, & 32*)	(7,806,822)	-	(7,806,822)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	38,245			(487)		37,758
3	302	Franchises and Consents	-					-
4	303	Miscellaneous Intangible Plant	9,457,804	475,519	(27,952)	(120,338)		9,785,033
5		TOTAL Intangible Plant	9,496,049	475,519	(27,952)	(120,825)	-	9,822,791
6		2. Production Plant						
7		Natural Gas Production & Gathering Plant						
8	325.1	Producing Lands	-					-
9	325.2	Producing Leaseholds	-					-
10	325.3	Gas Rights	-					-
11	325.4	Rights-of-Way	-					-
12	325.5	Other lLand and Land Rights	-					-
13	326	Gas Well Structures	-					-
14	327	Field Compressor Station Structures	-					-
15	328	Field Measuring and Regulating Station Structures	-					-
16	329	Other Structures	-					-
17	330	Producing Gas Wells- Well Construction	-					-
18	331	Producing Gas Wells- Well Equipment	-					-
19	332	Field Lines	-					-
20	333	Field Compressor Station Equipment	-					-
21	334	Field Eeasuring and Regulating Station Equipment	-					-
22	335	Drilling and Cleaning Equipment	-					-
23	336	Purification Equipment	-					-
24	337	Other Equipment	-					-
25	338	Unsuccessful Exploration & Development Costs	-					-
26		TOTAL Production & Gathering Plant	-	-	-	-	-	-
27		Products Extraction Plant						
28	340	Land and Land Rights	-					-
29	341	Structures and Improvements	-					-
30	342	Extraction and Refining Equipmnet	-					-
31	343	Pipe Lines	-					-
32	344	Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initally recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing sub-account classification of such plant conforming to the requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

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

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2019**

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

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		Total Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	-					-
80	365.2	Rights-of-Way	-					-
81	366	Structures and Improvements	-					-
82	367	Mains	-					-
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	-					-
85	370	Communication Equipment	-					-
86	371	Other Equipment	-					-
87		TOTAL Transmission Plant	-	-	-	-	-	-
88		5. Distribution Plant						
89	374	Land and Land Rights	23,867			(303)		23,564
90	375	Structures and Improvements	100,396	6,635	(1,062)	(1,277)		104,692
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	124,263	6,635	(1,062)	(1,580)	-	128,256

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
104		6. General Plant						
105	389	Land and Land Rights	240,110			(3,055)		237,055
106	390	Structures and Improvements	1,495,118	8,067		(19,023)		1,484,162
107	391	Office Furniture and Equipment	1,901,040	92,255		(24,188)		1,969,107
108	392	Transportation Equipment	513,992	87,478	(82,289)	(6,544)	19,970	532,607
109	393	Stores Equipment	10,837	2,303		(138)		13,002
110	394	Tools, Shop, and Garage Equipment	614,041	63,995	(859)	(7,813)		669,364
111	395	Laboratory Equipment	22,794		(1,529)	(291)		20,974
112	396	Power Operated Equipment	(24,319)	502		309		(23,508)
113	397	Communication Equipment	229,037	102,272		(2,913)		328,396
114	398	Miscellaneous Equipment	14,960			(190)		14,770
115		SUBTOTAL	5,017,610	356,872	(84,677)	(63,846)	19,970	5,245,929
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	5,017,610	356,872	(84,677)	(63,846)	19,970	5,245,929
118		TOTAL (Accounts 101 and 106)	14,637,922	839,026	(113,691)	(186,251)	19,970	15,196,976
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	14,637,922	839,026	(113,691)	(186,251)	19,970	15,196,976

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	T O T A L S -	0	0	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	387,387	
4			
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48	T O T A L -	387,387	0

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, 2019

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	(3,158,996)	(3,158,996)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(198,710)	(198,710)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(28,263)	(28,263)		
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*)	(226,973)	(226,973)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	85,744	85,744		
12	Cost of Removal	59	59		
13	Salvage (credits)	(22,871)	(22,871)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	62,932	62,932		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	510,424	510,424		
15.02	Adjustment Due to Change in Allocation Rate	35,385	35,385		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(2,777,228)	(2,777,228)		
	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	(103,784)	(103,784)		
26	General	(3,186,385)	(3,186,385)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	512,941	512,941		
27	TOTAL (*Total of Lines 18 thru 26*)	(2,777,228)	(2,777,228)		

NOTE:
Row 15 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

1. Report below the information called for concerning inventories of gas stored.
2. The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Mcf of inputs and withdrawals and balance for each project, except under certain specified circumstances. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and reason for any deviation from the general basis provided by the Uniform System of Accounts. Separate schedules on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.
3. If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment and account charged or credited.
4. Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
5. If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock", the inventory basis, and the accounting performed with respect to any encroachment of withdrawals upon "base stock", or restoration of previous encroachment including brief particulars of any such accounting during the year.
6. If respondent has provided accumulated provision for such stored gas which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of Commission authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, (e) a summary showing balance of accumulated provision and entires during year.
7. Pressure base of gas volumes reported in this schedule is 14.73 psia at 60" F.

Line No.	Description	NonCurrent (Acct 117) (a)	Current (Acct 164.1) (b)	LNG (Acct 164.2) (c)	LNG (Acct 164.3) (d)	Total (e)
1	Balance, beginning of year	Not allocated		Not allocated		Not allocated
2	Gas delivered to storage					
3	(contract account)					
4	Gas withdrawn from storage					
5	(contra account)			$ 242,806		$ 242,806
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					63,301
31	Amount per Mcf					3.84
32	Cost basis of withdrawals:					
33	Specify: average cost, lifo, fifo, (Explain any change in					F i f o
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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STATE OR OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804.1 and 805)

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

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

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

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

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

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

5. Column instructions are as follows:

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

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

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

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

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

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

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

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

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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**		
9			
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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

7 Code (d)	State Code (e)	County Code (f)	Rate Schedule No. (g)	Rate Schedule Suffix (h)	Date of Contract (I)	Approx. BTU Per Cu Ft (j)	Gas Purchased - Mcf (14.73 psia 60 °F) (k)	Cost of Gas (l)	Cost Per Mcf (cents) (m)	LINE NO.
										1
						10.79	8,072,321	$ 20,875,351	259	2
										3
								$ 578,100	n/a	4
										5
								$ 9,168,467	n/a	6
										7
							8,072,321	**$ 30,621,918**	n/a	8
										9
										10
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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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.

			Natural Gas			Manufactured Gas	
LINE NO.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	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	812	7,559	$ 15,089	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	**TOTAL**		7,559	$ 15,089			

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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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		8,072,321
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		8,072,321
14	Gas of others received for transportation		25,313,504
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		260,457
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		33,646,282

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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		710,666
39	(ii) Other distribution system sales		7,823,803
40	TOTAL DISTRIBUTION SYSTEM SALES		8,534,469
41	d. Interdepartmental sales		
42	TOTAL SALES		8,534,469
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		25,313,504
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		25,313,504
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		7,559
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		33,855,532
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		(209,250)
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		(209,250)
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		33,646,282

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - Miscellaneous General Expeness (Account 930.2)

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

LINE NO.	ITEMS (a)	TOTAL (b)	AMOUNT APPLICABLE TO STATE OF OREGON (c)	AMOUNT APPLICABLE TO OTHER STATES (d)
1	Industry association dues.	284,608	76,398	208,210
2	Experimental and general research expenses.			
	a. Gas Research Institute (GRI)			
	b. Other			
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing oustanding securities of the respondent			
4				
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex and MDU for CNGC's share of corporate banking fees)			
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	451,891	112,205	339,686
7	Miscellaneous under $250,000			
8	2,725 items	296,140	62,148	233,992
9				
10				
	TOTAL	**1,032,639**	**250,751**	**781,888**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - POLITICAL ADVERTISING

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

LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	NONE		
	TOTAL		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	Association of WA Business-Natural Gas Coalition Funds to be used to defeat Proposed Rule by City of Bellingham to ban the use of Natural Gas.	426.4	43,453
	TOTAL		**43,453.00**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	MDU/MDUR Allocated - approved in Order 07-418	107	2,130,631	529,036
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	211,302	52,466
3	MDU/MDUR Allocated - approved in Order 07-418	426.2	(569,914)	(141,510)
4	MDU/MDUR Allocated - approved in Order 07-418	426.4	306,254	76,043
5	MDU/MDUR Allocated - approved in Order 07-418	426.5	1,556	-
6	MDU/MDUR Allocated - approved in Order 07-418	813	172,370	42,800
7	MDU/MDUR Allocated - approved in Order 07-418	870	1,236,084	306,929
8	MDU/MDUR Allocated - approved in Order 07-418	874	465,129	226,068
9	MDU/MDUR Allocated - approved in Order 07-418	875	115,170	28,597
10	MDU/MDUR Allocated - approved in Order 07-418	878	-	-
11	MDU/MDUR Allocated - approved in Order 07-418	880	1,235,529	306,745
12	MDU/MDUR Allocated - approved in Order 07-418	881	69,876	8,606
13	MDU/MDUR Allocated - approved in Order 07-418	885	80,218	19,925
14	MDU/MDUR Allocated - approved in Order 07-418	887	619,344	18,563
15	MDU/MDUR Allocated - approved in Order 07-418	887.1	7,141	1,773
16	MDU/MDUR Allocated - approved in Order 07-418	892	200	50
17	MDU/MDUR Allocated - approved in Order 07-418	894	48,297	11,821
18	MDU/MDUR Allocated - approved in Order 07-418	901	44,898	11,148
19	MDU/MDUR Allocated - approved in Order 07-418	902	211,446	52,502
20	MDU/MDUR Allocated - approved in Order 07-418	903	5,336,032	1,324,937
21	MDU/MDUR Allocated - approved in Order 07-418	904	1,209,258	215,041
22	MDU/MDUR Allocated - approved in Order 07-418	908	279,237	62,967
23	MDU/MDUR Allocated - approved in Order 07-418	909	166,830	51,574
24	MDU/MDUR Allocated - approved in Order 07-418	920	7,255,805	1,801,616
25	MDU/MDUR Allocated - approved in Order 07-418	921	3,391,431	842,020
26	MDU/MDUR Allocated - approved in Order 07-418	922	(245,018)	(60,728)
27	MDU/MDUR Allocated - approved in Order 07-418	923	267,373	67,930
28	MDU/MDUR Allocated - approved in Order 07-418	925	9,351	2,322
29	MDU/MDUR Allocated - approved in Order 07-418	926	28,351	7,040
30	MDU/MDUR Allocated - approved in Order 07-418	930.1	30,962	7,688
31	MDU/MDUR Allocated - approved in Order 07-418	930.2	753,502	187,093
32	MDU/MDUR Allocated - approved in Order 07-418	931	1,384,279	343,716
33	MDU/MDUR Allocated - approved in Order 07-418	932	2,101	522
34	Other Services	VAR	-	-
	TOTALS		26,255,025	6,405,300

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - Donations and Memberships

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

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	*(a) Contributions to and memberships in charitable organizations:*			
2	*MDU Resources Foundation (Bismarck, ND)*	426.1	113,246	28,119
3	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,415
4	United Way (WA and OR)	426.1	1,945	859
5	Other Organizations (41 organizations)	908.0/930.2/921.0	19,375	12,875
6	Total contributions to and memberships in charitable organizations		184,566	54,268
7	*(b) Organizations of the Utility Industry:*			
8	American Gas Association (Washington D.C.)	426.4/930.2	117,855	29,263
9	Northwest Gas Association (West Linn, OR)	930.2	55,218	13,711
10	Western Energy Institute (Portland, OR)	921.0/930.2	10,120	2,513
11	North American Energy Standards Board (Houston, TX)	921.0	7,500	1,862
12	Other Organizations (6 organizations)	908.0/930.2/921.0	3,806	1,535
13	Total contributions to Organizations of the Utility Industry		194,499	48,884
14	*(c) Technical and Professional Organizations*			
15	National Association of Corrosion Engineers (Houston, TX)	921.0	2,000	497
16	CPA State Boards and Societies	921.0	1,351	335
17	PE State Boards and Societies	921.0/870.0	613	152
18	Other Organizations (20 organizations)	921.0/930.2	5,212	1,294
19	Total contributions to Professional Organizations		9,176	2,278
20	*(d) Commercial and Trade Organizations*			
21	Association of Washington Business (Olympia, WA)	930.2/921.0	47,475	11,788
22	Chamber of Commerce-13 (OR)	880.0/930.2	26,981	14,916
23	Economic Development Councils-5 (OR)	426.1/930.2	20,681	13,165
24	Other Organizations (3 organizations)	426.1/908.0/930.2	4,927	1,356
25	Total contributions to Commercial and Trade Organizations		100,064	41,225
26	*(e) Other Organizations & Donations*			
27	MDU Resources expenses (Bismarck, ND)	426.1/426.4/921.0	34,116	8,471
28	Grandridge Business Park (Kennewick WA)	921.0	10,181	2,528
29	Other Organizations	930.2	50	50
30	Total Other Organizations		44,347	11,049
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
	TOTAL		**532,652**	**157,704**

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, 2019**

STATE OF OREGON - OFFICERS' SALARIES

1. Report below the name, title and salary for the year for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principle business unit, division or function (such as sales, administration or finance) and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and date the change in incumbency was made.
3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

LINE NO.	TITLE (a)	NAME OF OFFICER (b)	SALARY FOR YEAR TOTAL (a)	SALARY FOR YEAR OREGON (a)
1	Assistant Secretary 2/	Julie A. Krenz	4/	
2	Assistant Secretary 2/	Karl A. Liepitz	4/	
3	Chairman of the Board 2/	David L. Goodin	4/	
4	Chief Information Officer 2/	Margaret (Peggy) A. Link	4/	
5	Controller 1/	Tammy J. Nygard	4/	
6	Executive VP -Reg Affairs, Cust Service & Administration/1	Garret Senger	4/	
7	Executive VP-Bus Development & Gas Supply 1/	Scott W. Madison	4/	
8	General Counsel and Secretary 2/	Daniel S. Kuntz	4/	
9	President and CEO of MDU Utilities Group 1/	Nicole A. Kivisto	4/	
10	Treasurer 2/	Jason L. Vollmer	4/	
11	VP Field Operations 1/	Eric P. Martuscelli	4/	
12	VP-Engineering & Operations Services 1/	Patrick C. Darras	4/	
13	VP-Human Resources 2/	Anne M. Jones	4/	
14	VP-Regulatory Affairs & Cust Service 1/	Mark A. Chiles	4/	
15	VP-Safety, Process Improvement & Operating Systems 1/	Hart Gilchrist	4/	
16				
17				
18	1/ Salary includes amount allocated to CNGC from MDU			
19	2/ Salary includes amount allocated to CNGC from MDUR			
20	4/ Confidential salary data included on filed reports with OPUC.			
21				
22				
23				
24				
25				

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

LINE NO.	NAME OF RECIPIENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Eugene Water & Electric Board	Construction	743,205
2	Heath consultants, Inc.	Construction	189,789
3	McDowell Rackner & Gibson	Consulting	93,477
4	Brothers Pipeline Corp.	Construction	74,418
5	Deloite & Touche	Audit	68,562
6	Das-CO of Idaho	Construction	55,980
7	One Call Concepts, Inc.	Construction	27,895
8	Knife River-Western OR	Construction	25,818
9	Other		6,390
10			
11			
12			
13			
14			
15			
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20			
21			
22			
23			
24			
25			
	TOTAL		**1,285,534**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

Oregon Production Statistics (therms)	
Gas Produced	
Gas Purchased	362,992,918
Total Receipts	362,992,918
Gas Sales	365,168,867
Gas used by Company	81,548
Gas Delivered to LNG Storage - Net	
Losses & Billing Delay	(2,257,497)
Total Disbursements	362,992,918
Oregon Revenue by Service Class	
Residential	$ 37,648,100
Commercial & Industrial	$ 25,020,626
Firm	
Interruptible	
Transportation	$ 4,432,276
Total	$ 67,101,002
Gas Sold in Therms (Oregon)	
Residential	49,965,826
Commercial & Industrial	42,108,299
Firm	
Interruptible	
Transportation	273,094,742
Total	365,168,867
Average Number of Customers	
Residential	65,860
Commercial & Industrial	10,305
Firm	
Interruptible	
Transportation	37
Total	76,202

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, 2019

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 Terminaling and Processing				
32	Transmission				
33	Distribution	3,338,854			**3,338,854**
34	Customer Accounts	1,049,373			**1,049,373**
35	Customer Service and Informational	159,236			**159,236**
36	Sales	940			**940**
37	Administrative and General	1,496,715			**1,496,715**
38	TOTAL Operation (Total of lines 28 thru 37)	**6,045,118**	**-**	**-**	**6,045,118**
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	1,000,880			**1,000,880**
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	**1,000,880**	**-**	**-**	**1,000,880**
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)				
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	4,339,734			**4,339,734**
56	Customer Accounts (Total of line 34)	1,049,373			**1,049,373**
57	Customer Service and Informational (Total of line 35)	159,236			**159,236**
58	Sales (Total of line 36)	940			**940**
59	Administrative and General (Total of lines 37 and 46)	1,496,715			**1,496,715**
60	Total Operation and Maintenance (Total of lines 50 thru 59)	**7,045,998**	**-**	**-**	**7,045,998**
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	**7,045,998**	**-**	**-**	**7,045,998**
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	1,943,262			**1,943,262**
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	**1,943,262**	**-**	**-**	**1,943,262**
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	163,414			**163,414**
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	**163,414**	**-**	**-**	**163,414**
75	PTO/Incentive/Severance Pay Liabilities	421,399			**421,399**
76	TOTAL Other Accounts	**421,399**	**-**	**-**	**421,399**
77	TOTAL SALARIES AND WAGES	**9,574,073**	**-**	**-**	**9,574,073**

2019

MDU Resources Group, Inc.

Annual Report | Form 10-K | Proxy Statement

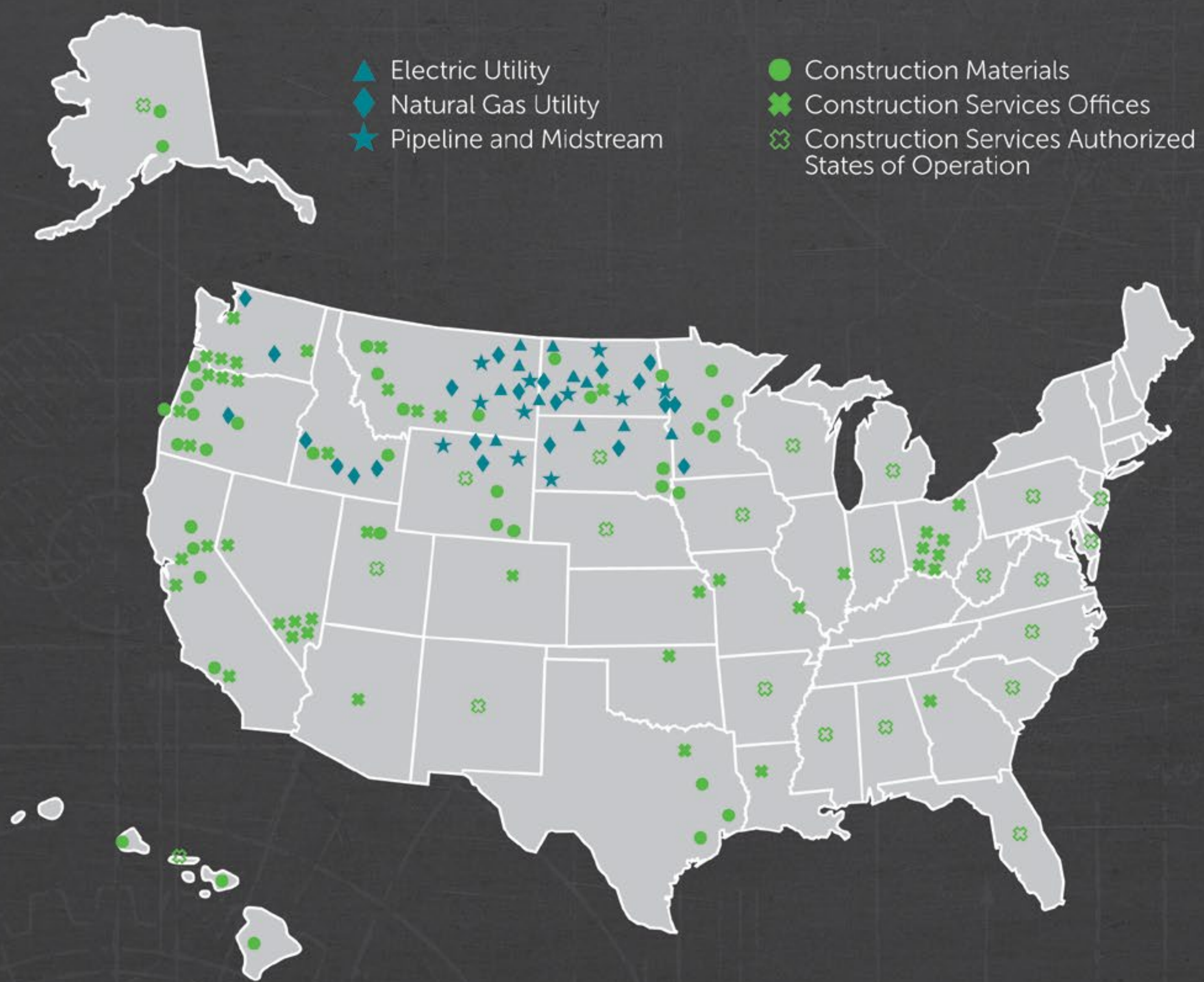
Building a Strong America®

MDU RESOURCES GROUP, INC.

MDU RESOURCES
GROUP, INC.

Building a Strong America®

2019



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

Conducting business in 43 states

13,359 employees

2.05 Bcf/day of natural gas pipeline capacity

1.1 million utility customers

12th largest specialty contractor, according to Engineering News-Record

1.1 billion tons of aggregate reserves

2019 annual dividend per share: 82 cents

Paid dividends 82 consecutive years

Increased dividends 29 consecutive years

2019 earnings: $335.5 million / $1.69 EPS

At December 31, 2019.

Highlights

Years ended December 31,	2019	2018
	(In millions, where applicable)	
Operating revenues	$5,336.8	$4,531.6
Operating income	$ 481.2	$ 401.7
Net Income	$ 335.5	$ 272.3
Earnings per share	$ 1.69	$ 1.39
Dividends declared per share	$ .815	$ .795
Weighted average shares outstanding — diluted	198.6	196.1
Total assets	$ 7,683	$ 6,988
Total equity	$ 2,847	$ 2,567
Total debt	$ 2,243	$ 2,109
Capitalization ratios:		
Total equity	55.9%	54.9%
Total debt	44.1	45.1
	100%	100%
Price/earnings from continuing operations ratio (12 months ended)	17.6x	17.3x
Book value per share	$ 14.21	$ 13.09
Market value as a percent of book value	209.1%	182.1%
Employees	13,359	11,797

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 "2019 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.

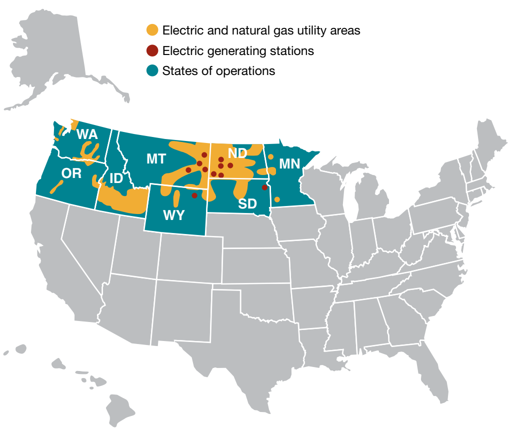
Regulated Energy Delivery

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 Minnesota and North Dakota. Intermountain Gas Company distributes natural gas in 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.

2019 Key Statistics

Revenues (millions)	
Electric	$351.7
Natural gas	$865.2
Earnings (millions)	
Electric	$54.8
Natural gas	$39.5
Electric retail sales (million kWh)	3,314.3
Natural gas distribution (MMdk)	
Retail sales	123.7
Transportation sales	166.1



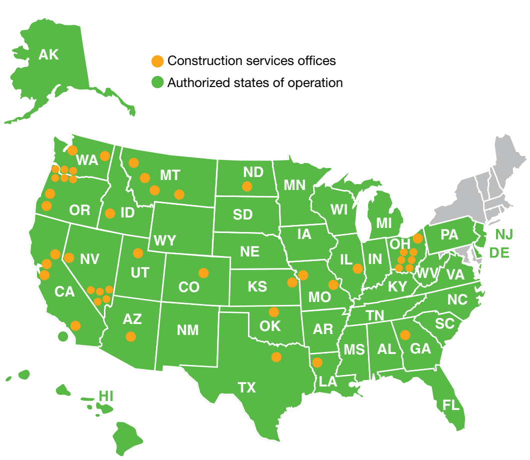
Construction Materials and Services

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.

2019 Key Statistics

Revenues (millions)	$1,849.3
Earnings (millions)	$93.0



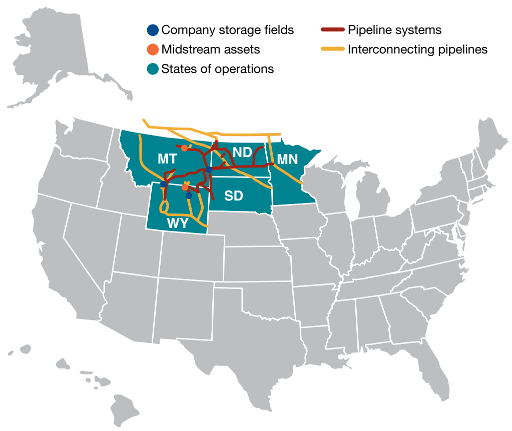
Regulated Energy Delivery

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.

2019 Key Statistics

Revenues (millions)	$140.4
Earnings (millions)	$29.6
Pipeline (MMdk)	
Transportation	429.7
Gathering	13.9



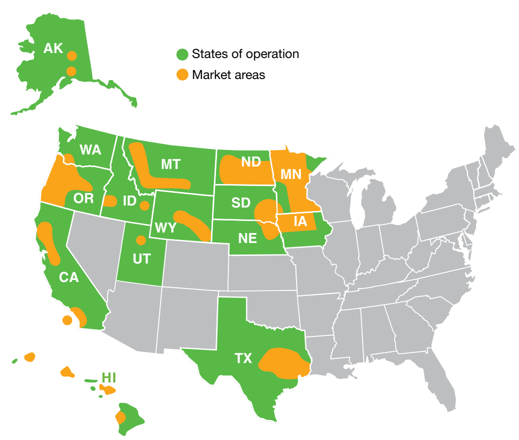
Construction Materials and Services

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.

2019 Key Statistics

Revenues (millions)	$2,190.7
Earnings (millions)	$120.4
Construction materials sales (thousands)	
Aggregates (tons)	32,314
Asphalt (tons)	6,707
Ready-mix concrete (cubic yards)	4,123
Construction materials aggregate reserves (billion tons)	1.1



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

Report to Stockholders

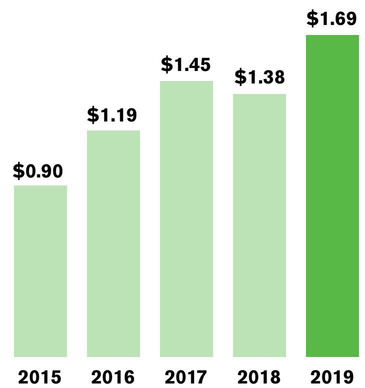
Our team of employees safely and successfully continues our efforts toward Building a Strong America® by providing electricity and natural gas to homes and businesses, while building the infrastructure to make that possible and constructing the roads and runways for our country's transportation system.

MDU Resources Group increased earnings 23% in 2019, with outstanding performance from both our construction operations and our regulated energy delivery businesses. Earnings in 2019 were $335.5 million, or $1.69 per share, compared to 2018 earnings of $272.3 million, or $1.39 per share.

During 2019, we provided you with a 28% total return on your investment in MDU Resources stock. This included increasing our dividend for the 29th consecutive year. These results emphasize the success of our two-pillar approach of expanding both our regulated energy delivery businesses and construction materials and services businesses that are strategically located in growing markets across the country.

We anticipate 2020 will be another strong year, with record combined project backlog at the start of the year at our construction businesses, significant growth projects at our natural gas pipeline company and infrastructure upgrades and replacements at our utility operations to serve a growing customer base. With $650 million in expected capital projects this year as part of approximately $2.9 billion in planned investments over the next five years, we believe MDU Resources will continue to provide you with the long-term returns you expect.

Earnings Per Share
(from continuing operations)



Construction services continues breaking records

For the second consecutive year, MDU Construction Services Group had record revenues, earnings and backlog. Earnings were $93.0 million, a 45% increase over 2018 earnings of $64.3 million, while year-over-year revenues were 35% higher.

We saw higher workloads and margins in 2019 from our outside specialty electrical contracting operations, with an increase in work for utility customers, and we continued to see strong demand for sales and rentals of the utility construction equipment we manufacture.

There also continues to be high demand for the inside specialty electrical and mechanical contracting work we perform, particularly in the hospitality, high-tech and manufacturing industries, and we have strong relationships with the customers for whom we provide top-quality services.

Our team of employees consistently delivers successful design and build projects across the country, and our footprint is growing as we acquired two operations in the past year. In mid-2019, we acquired the assets of Pride Electric, Inc., a leading electrical construction company in Redmond, Washington. In early 2020, we acquired PerLectric, Inc., a leading electrical construction company in Fairfax, Virginia. We continue to explore opportunities for further growth through acquisitions that are a good strategic fit with our existing operations.

MDU Construction Services Group is the 12th largest specialty contractor in the U.S., according to Engineering News Record's "2019 Top 600 Specialty Contractors" list, and we have more than 7,000 skilled employees at peak construction season working across 42 states for this business. With a record work backlog of $1.14 billion at the end of 2019, which was a 22% increase over $939 million at December 31, 2018, we expect strong results from this business again in 2020.

Acquisitions help grow construction materials

Knife River Corporation earned $120.4 million in 2019, a 30% increase compared to $92.6 million in 2018.

Like our construction services operations, we saw higher workloads at this business unit in 2019. Strong economic conditions in most of the states where we operate resulted in an increase in materials sales as well as higher contracting workloads and margins. We also benefited from an increase in asset sales gains that were approximately $5.6 million higher, after tax, than in 2018.

We completed a platform acquisition and a number of bolt-on acquisitions in 2018 and 2019 that have contributed to earnings growth. We continue our acquisition strategy in this business, and just announced on February 14 that we acquired an operation in Spokane, Washington, that produces precast and prestressed concrete components for projects throughout Washington, Idaho and Oregon. This acquisition complements and expands Knife River's existing precast and prestressed operations in Oregon and Alaska, allowing us to better serve the growing Pacific Northwest.

Knife River is installing equipment and rail infrastructure at a substantial new aggregate quarry in Texas, for which it received in the fourth quarter of 2019 an Air Quality Standard permit to construct a rock-crushing plant. The 570-acre Honey

Dennis W. Johnson
Chair of the Board

David L. Goodin
President and Chief Executive Officer

Creek Quarry contains an estimated 40-year supply of high-quality aggregates that will supply our Texas ready-mix concrete, asphalt and construction operations, as well as third-party customers. Knife River expects aggregate production to begin there this year.

We continue to see strong bidding opportunities across our markets. Knife River's year-end 2019 backlog of work is on par with the previous year's record, at $693 million compared to $706 million, respectively. With state and federal officials recognizing that infrastructure repairs and replacements are overdue in many areas, we are ready with our 1.1 billion tons of aggregate reserves to serve the needs of our country.

Utility customer count, rate base continue to grow

Our electric and natural gas utility business earned a record $94.3 million in 2019, compared to $84.7 million in 2018. Natural gas sales volumes increased 9.9% and electric sales volumes declined 1.2%. The increase in natural gas sales volumes primarily was the result of colder weather across our eight-state service territory, with results partially offset by weather normalization mechanisms in most jurisdictions. Our utility customer base of approximately 1.1 million customers grew again in 2019 by 1.8%, and we anticipate it will continue to grow annually by 1% to 2%.

We had extensive rate-related regulatory activity in 2019 and expect that to continue in 2020. In 2019, our team completed a natural gas case in Oregon and an electric case in Montana, implementing approximately $11 million in annual rate increases. In early 2020, we completed a natural gas case in Washington, with approximately $6.5 million in annual rate increases to begin March 1. Our utility companies also completed rate adjustments that were necessary in every jurisdiction to return to customers the benefits of lower federal income taxes. In total, those adjustments provide approximately $31 million in annual rate reductions to our customers. Our companies have two additional rate cases pending before state utility commissions, and we anticipate filing additional requests this year to earn recovery on costs associated with upgrading and expanding our facilities to safely meet customer demand. We are forecasting compounded annual growth of 5% over the next five years on our $2.4 billion rate base.

Our utility companies, Cascade Natural Gas Corporation, Intermountain Gas Company and Montana-Dakota Utilities Co., took first, second and third places, respectively, in the West Midsize Segment of the J.D. Power 2019 Gas Utility Residential Customer Satisfaction Study.SM In addition, Cascade Natural Gas took first place nationwide in the survey — a significant accomplishment based on complimentary feedback from our customers. We are proud of the women and men who serve our customers every day with reliable and safe natural gas service, including our Customer Experience Team headquartered in Meridian, Idaho, which handles approximately 1.5 million natural gas and electric utility customer inquiries per year.

We continue to focus on upgrading and replacing aging natural gas distribution pipeline with the safest, most up-to-date distribution materials available. We are fortunate not to have any cast-iron pipe in our system, which has been identified industrywide as a higher safety risk.

As we announced in early 2019, we are proceeding with efforts to retire the Lewis & Clark Station at Sidney, Montana, and the Heskett 1 and 2 units at Mandan, North Dakota. We expect to close these coal-fired electric generating facilities, with a combined capacity of 144 megawatts, at the end of first quarter 2020 and 2021, respectively, and replace them with an 88-MW natural gas-fired peaking unit to be built at the Heskett site, as well as purchasing low-cost power available to us as a member of the Midcontinent Independent System Operator market. Replacing these outdated plants, which were built in the 1950s and early 1960s, will reduce costs for our electric customers while also reducing our greenhouse gas emissions from power generation sources.

Pipeline has third year of record volumes

Our pipeline and midstream business earned $29.6 million in 2019, compared to $28.5 million in 2018. Results in 2018 included a $4.2 million tax benefit related to a final accounting order issued by the Federal Energy Regulatory Commission.

WBI Energy transported a record volume of natural gas for the third consecutive year, approximately 22% more than in 2018. These volume increases are partly due to organic growth projects on our pipeline system that provide additional capacity to third-party producers in the Bakken region, where natural gas flaring continues to exceed state-imposed restrictions.

We completed construction and placed into service in September the Demicks Lake project in McKenzie County, North Dakota, which added approximately 175 million cubic feet per day of capacity. Line Section 22, an expansion project near Billings, Montana, was put into service in November and adds approximately 22.5 MMcf/day of capacity. The Demicks Lake Expansion project also was just completed and put into service at the beginning of February this year. It adds another 175 MMcf/day of capacity. In total, our interstate pipeline system now has capacity to transport more than 2.2 billion cubic feet of natural gas per day.

WBI Energy also benefited in 2019 from a FERC-approved rate increase that took effect May 1. The increase includes higher customer and depreciation rates, which will allow WBI Energy to invest more in system upgrades each year.

WBI Energy continues to propose solutions to assist in the gas flaring challenges in North Dakota, where producer demand remains high for additional natural gas pipeline capacity. We just filed our application with the FERC for permission to proceed with construction in 2021 on the North Bakken Expansion project in western North Dakota, which will add approximately 350 MMcf/day of capacity.

Company sustainability remains a strong focus

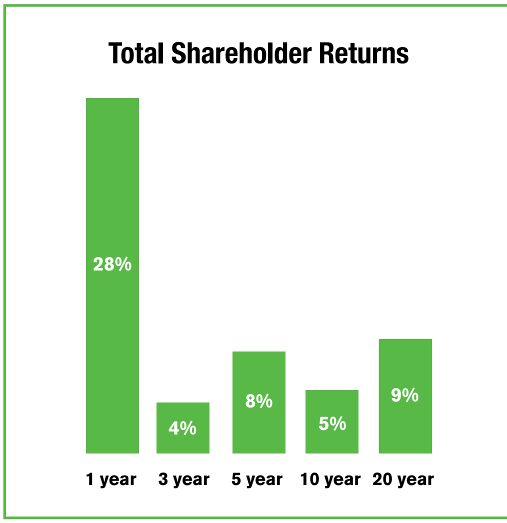
We recognize that the sustainability of our operations hinges on public perception and policy, which are greatly impacted by our role as a corporate citizen in the communities we serve across the country. In 2019, our board sharpened its focus on environmental and social matters by establishing an Environmental and Sustainability Committee. The committee helps fulfill the board's oversight responsibilities by providing recommendations on company policies, strategies, public policy positions, programs and performance related to environmental, workplace health and safety, and other social sustainability matters.

We also provided you in 2019 with a deeper look at our environmental, social and governance efforts through more extensive reporting in those areas. We adapted our ESG reporting to follow the standards outlined by the Sustainability Accounting Standards Board and other industry organizations, and this information is now available on our website at www.mdu.com/sustainability. We will continue to focus on expanding our metrics and reporting in regard to ESG matters.

Also related to ensuring our operations are sustainable, we maintain our focus on the safety of our employees, the public and our operations. Our employee safety records continue to beat industry rates, and we remain committed to ensuring our systems provide safe and reliable service to customers across our operations.

We also continue to enhance our cybersecurity measures to keep our systems, data and customer information safe.

Keeping our operations and hardworking employees safe helps ensure we can provide you with the long-term returns you expect from MDU Resources. As part of our pledge to deliver results to you, this was the 82nd consecutive year we have paid a competitive dividend, while increasing it each of the past 29 years. Our board remains committed to maintaining this tradition for our shareholders.



Alongside all of MDU Resources' directors and employees, we thank you for your investment in our company. We look forward to continuing to provide the essential energy and construction products and services that are Building a Strong America.®

Dennis W. Johnson
Chair of the Board

David L. Goodin
President and Chief Executive Officer

February 21, 2020

Board of Directors

From left, Chenxi Wang, John K. Wilson, Dennis W. Johnson, Mark A. Hellerstein, David L. Goodin, David M. Sparby, Patricia L. Moss, Thomas Everist, Edward A. Ryan and Karen B. Fagg.

Dennis W. Johnson
70 (19)
Dickinson, North Dakota

Chair of MDU Resources Board of Directors

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

Expertise: Business management, specialty contracting, finance and strategic planning.

David L. Goodin
58 (7)
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
70 (25)
Sioux Falls, South Dakota

President and chair of The Everist Co., formerly a construction materials company; a director of Raven Industries, Inc., a public company.

Expertise: Construction materials and contracting industry, business leadership and management.

Karen B. Fagg
66 (15)
Billings, Montana

Retired, formerly vice president of DOWL HKM and formerly chair, chief executive officer and majority owner of HKM Engineering Inc.

Expertise: Engineering, natural resource development, environment and business management.

Mark A. Hellerstein
67 (7)
Denver, Colorado

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

Expertise: Accounting, finance, business leadership and public company management.

Patricia L. Moss
66 (17)
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., a public company.

Expertise: Finance, compliance oversight, business development and public company governance.

Edward A. Ryan
66 (2)
Washington, D.C.

Formerly executive vice president and general counsel of Marriott International, a large public company with international operations.

Expertise: Corporate governance and transactions, legal and public company leadership.

David M. Sparby
65 (2)
Minneapolis, Minnesota

Formerly senior vice president and group president, Revenue at Xcel Energy Inc. and president and chief executive officer of Northern States Power-Minnesota.

Expertise: Public utility, renewable energy, finance, legal and public company leadership.

Chenxi Wang
49 (1)
Los Altos, California

Founder and managing general partner of Rain Capital Fund LP, a cybersecurity-focused venture fund; formerly chief strategy officer of Twistlock, a security software company.

Expertise: Technology, cybersecurity, capital markets and business development.

John K. Wilson
65 (17)
Omaha, Nebraska

Formerly president of Durham Resources LLC, a privately held financial management company, and formerly a director of a mutual fund.

Expertise: Accounting, finance, public utility and business management.

Director Changes

Harry J. Pearce did not stand for re-election in 2019. His term as a director and chair of the MDU Resources Board of Directors concluded May 7, 2019.

William E. McCracken did not stand for re-election in 2019. His term as a director concluded May 7, 2019.

Chenxi Wang was elected to the Board of Directors on May 7, 2019.

Dennis W. Johnson was named chair of the MDU Resources Board of Directors on May 7, 2019.

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2019.

Corporate Management

David L. Goodin
58 (37)

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
64 (34)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River.

Trevor J. Hastings
46 (24)

President and Chief Executive Officer of WBI Holdings, Inc.

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

Anne M. Jones
56 (38)

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
46 (25)

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

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

Daniel S. Kuntz
66 (16)

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
53 (15)

Vice President and Chief Information Officer of MDU Resources

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

Jeffrey S. Thiede
57 (16)

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
42 (15)

Vice President, Chief Financial Officer and Treasurer of MDU Resources

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

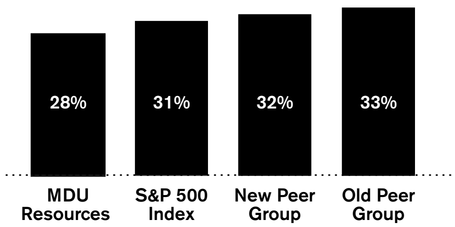
Numbers indicate age and years of service ( ) as of December 31, 2019.

From left, Trevor J. Hastings, Anne M. Jones, Jeffrey S. Thiede, David C. Barney, David L. Goodin, Nicole A. Kivisto, Jason L. Vollmer, Peggy A. Link and Daniel S. Kuntz.

Stockholder Return Comparison

Comparison of One-Year Total Stockholder Return

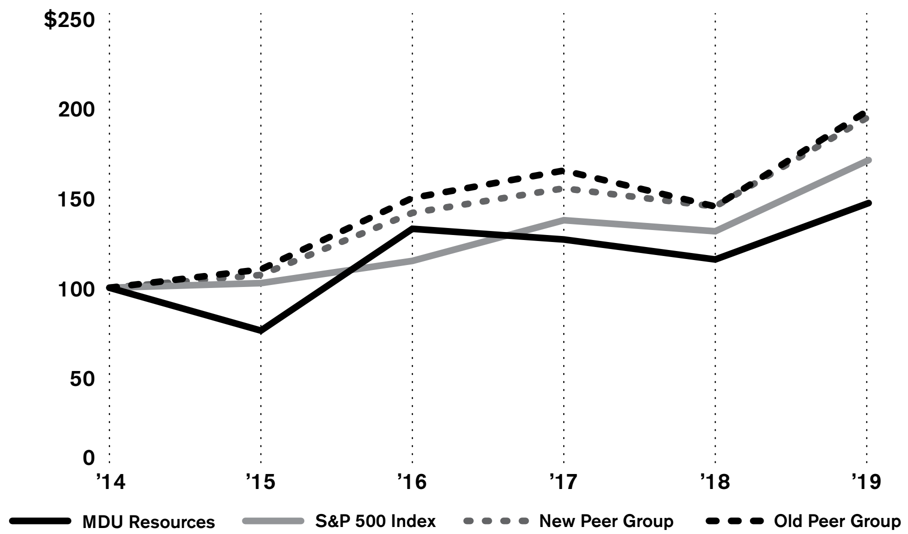
(as of December 31, 2019)



An explanation of the peer group is provided on the following page.

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

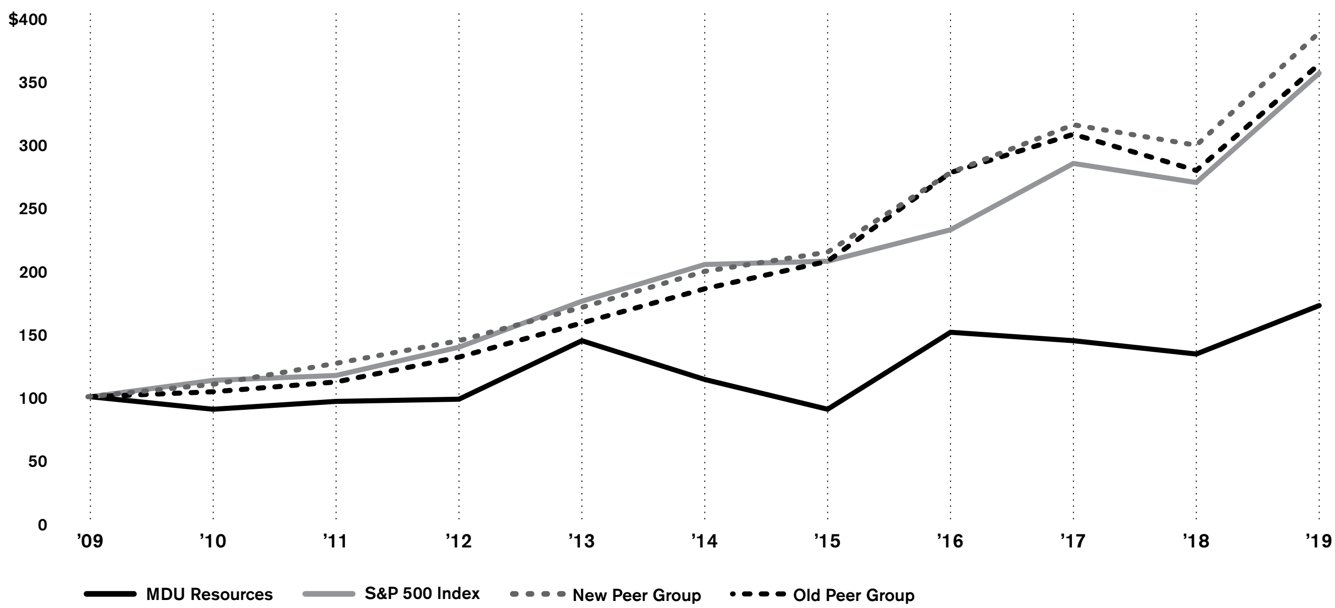
$100 invested December 31, 2014, in MDU Resources was worth $148.48 at year-end 2019.



	2014	2015	2016	2017	2018	2019
MDU Resources Group, Inc.	$100.00	$81.12	$131.63	$126.54	$115.60	$148.48
S&P 500 Index	100.00	101.38	113.51	138.29	132.23	173.86
New Peer Group	100.00	107.28	140.13	157.81	149.74	197.49
Old Peer Group	100.00	111.43	150.78	166.75	149.20	198.24

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

$100 invested December 31, 2009, in MDU Resources was worth $170.76 at year-end 2019.



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MDU Resources Group, Inc.	$100.00	$88.70	$96.83	$98.84	$145.93	$115.01	$93.29	$151.38	$145.53	$132.95	$170.76
S&P 500 Index	100.00	115.06	117.49	136.30	180.44	205.14	207.98	232.85	283.69	271.25	356.66
New Peer Group	100.00	114.35	127.83	143.56	174.40	200.09	214.65	280.39	315.77	299.61	395.15
Old Peer Group	100.00	106.98	113.41	131.84	160.27	186.06	207.32	280.54	310.27	277.61	368.86

Stockholder Return Comparison

Data is indexed to December 31, 2019, for the one-year total stockholder return comparison, December 31, 2014, for the five-year total stockholder return comparison and December 31, 2009, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer groups. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group are weighted according to the issuer's stock market capitalization at the beginning of the period.

Effective January 1, 2019, a new peer group was established. These changes were made to better reflect the makeup of the company relative to each business segment's size and nature of business. The charts show stockholder return performance for both the old and new peer groups.

The new peer group issuers are Alliant Energy Corporation, Ameren Corporation, Atmos Energy Corporation, Black Hills Corporation, CMS Energy Corporation, Dycom Industries, Inc., EMCOR Group, Inc., Evergy, Inc., Granite Construction Incorporated, Jacobs Engineering Group Inc., KBR, Inc., Martin Marietta Materials, Inc., MasTec, Inc., NiSource Inc., Pinnacle West Capital Corporation, Portland General Electric Company, Quanta Services, Inc., Southwest Gas Holding, Inc., Summit Materials, Inc., Vulcan Materials Company and WEC Energy Group, Inc.

The old peer group issuers were ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, IDACORP, Inc., Martin Marietta Materials, Inc., MasTec, Inc., MYR Group Inc., Northwest Natural Holding Company (formerly Northwest Natural Gas Company), NorthWestern Corporation, Otter Tail Corporation, Portland General Electric Company, Southwest Gas Holding, Inc., Spire Inc., Summit Materials, Inc., U.S. Concrete, Inc., and Vulcan Materials Company. Vectren Corporation was originally an issuer in this peer group but was purchased by Centerpoint Energy in February 2019 and, as such, is no longer included in this peer group.

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, 2019

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	30-1133956
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

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

Title of each class	Trading symbol(s)	Name of each exchange on which registered
Common Stock, par value $1.00 per share	MDU	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 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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐.

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.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		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 Act). Yes ☐ No ☒.

State the aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 28, 2019: $5,134,204,876.

Indicate the number of shares outstanding of the registrant's common stock, as of February 13, 2020: 200,389,708 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Relevant portions of the registrant's 2020 Proxy Statement, to be filed no later than 120 days from December 31, 2019, are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Part II (continued)

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Audit Committee	Audit Committee of the board of directors of the Company
Bcf	Billion cubic feet
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota (50 percent ownership)
Btu	British thermal unit
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. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
CyROC	Cyber Risk Oversight Committee
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet Specialty Products Partners, L.P. (previously included in the Company's refining segment)
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 prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
GVTC	Generation Verification Test Capacity

Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
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
LIBOR	London Inter-bank Offered Rate
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana–Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquids
Non-GAAP	Not in accordance with GAAP
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
PCBs	Polychlorinated biphenyls
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream's 50 percent ownership interests were sold effective January 1, 2017)
Proxy Statement	Company's 2020 Proxy Statement to be filed no later than April 29, 2020
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations

Sheridan System	A separate electric system owned by Montana-Dakota
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
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 percent ownership)
WYPSC	Wyoming Public Service Commission
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - MD&A - 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. Montana-Dakota was incorporated under the state laws of Delaware in 1924. The Company was incorporated under the state laws of Delaware in 2018. Its principal executive offices are located at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota becoming a subsidiary of the Company. The merger was conducted pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the stockholders of the constituent corporation. Immediately after consummation of the Holding Company Reorganization, the Company had, on a consolidated basis, the same assets, businesses and operations as Montana-Dakota had immediately prior to the consummation of the Holding Company Reorganization. As a result of the Holding Company Reorganization, the Company became the successor issuer to Montana-Dakota pursuant to Rule 12g-3(a) of the Exchange Act, and as a result, the Company's common stock was deemed registered under Section 12(b) of the Exchange Act.

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-mixed 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 business 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.

The Company, through its wholly owned subsidiary, MDU Energy Capital, owns Montana-Dakota, Cascade and Intermountain. The electric segment is comprised of Montana-Dakota while the natural gas distribution segment is comprised of Montana-Dakota, Cascade and Intermountain.

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.

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 16 and Supplementary Financial Information.

The Company's material 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 Company seeks to align the interest of its board of directors and management with that of its shareholders. The Company believes that an independent, well-diversified board of directors makes it a better corporate citizen. The Company's board includes individuals of ethnic, gender and skill diversity. The Company also believes that its separation of chairman and chief executive officer further enhances accountability and social responsibility. The Company's management and its board of directors also have significant ownership in the Company's common stock, which further aligns their interests with those of other shareholders.

Employees The Company hires its employees from a number of sources, including within its various industries, trade schools, colleges and universities. The primary sources for its employees include promotion from within, team member referrals, union workforce, direct recruiting and various forms of advertising, including social media. The Company attracts and retains employees by offering competitive salaries, technical training opportunities, employee incentive programs and a comprehensive benefits package. The Company believes its focus on training and career development helps it to attract and retain employees. The Company's employees participate in ongoing educational programs to enhance their technical and management skills through classroom and field training. The Company provides opportunities for promotion and mobility within the organization, which also helps to retain employees.

As of December 31, 2019, the Company had 13,359 employees with 244 employed at MDU Resources Group, Inc., 1,578 at MDU Energy Capital, 335 at WBI Holdings, 4,255 at Knife River and 6,947 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 Company has a number of employees represented by 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 following information is as of December 31, 2019.

- At Montana-Dakota and WBI Energy Transmission, 333 and 71 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2021, and March 31, 2022, respectively.
- At Cascade, 192 employees are represented by the ICWU. The labor contract with the field operations group is effective through March 31, 2021.
- At Intermountain, 127 employees are represented by the UA. Labor contracts with such employees are in effect through March 31, 2023.
- Knife River operates under 42 labor contracts that represent 681 of its construction materials and contracting employees. Knife River is in negotiations on six of its labor contracts.
- MDU Construction Services has 107 labor contracts representing the majority of its employees. MDU Construction Services is in negotiations on four of its labor contracts.

Environmental Matters 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 20. There are no pending CERCLA actions for any of the Company's material properties. However, the Company is involved in certain claims relating to the Portland, Oregon, Harbor Superfund Site and the Bremerton Gasworks Superfund Site. For more information on the Company's environmental matters, see Item 8 - Note 20.

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.

Technology The Company uses technology in substantially all aspects of its business operations and requires uninterrupted operation of information technology systems and network infrastructure. These systems may be vulnerable to failures or unauthorized access. The Company has policies, procedures and processes in place designed to strengthen and protect these systems, which includes the Company's enterprise information technology and operation technology groups continually evaluating new tools and techniques that can be implemented to reduce the risk of a cyber breach.

The Company created CyROC to oversee the Company's approach to cybersecurity. CyROC is responsible for supplying management at all levels and the Audit Committee with analyses, appraisals, recommendations and pertinent information concerning cyber defense of the Company's electronic information and information technology systems. CyROC provides a quarterly cybersecurity report to the Audit Committee. For a discussion of the Company's risks related to cybersecurity, see Item 1A - Risk Factors.

Available Information 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. The SEC also maintains a website where the Company's filings can be obtained free of charge at www.SEC.gov.

Electric

General The Company's electric segment is operated through its wholly owned subsidiary, MDU Energy Capital, which consists of operations from Montana-Dakota. Montana-Dakota provides electric service at retail, serving 143,346 residential, commercial, industrial and municipal customers in 185 communities and adjacent rural areas in Montana, North Dakota, South Dakota and Wyoming as of December 31, 2019. For more information on the retail customer classes served, see the table below. The material properties owned by Montana-Dakota for use in its electric operations include interests in 16 electric generating units at 11 facilities and two small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,300 and 4,800 miles of transmission and distribution lines, respectively, and 79 transmission and 297 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, 2019, Montana-Dakota's net electric plant investment was $1.6 billion and its rate base was $1.2 billion.

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

	2019		2018		2017	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**118,563**	**$ 125,614**	118,426	$ 126,173	118,379	$ 121,171
Commercial	**22,948**	**142,062**	22,756	141,961	22,764	140,856
Industrial	**234**	**37,790**	236	36,081	242	34,417
Other	**1,601**	**7,454**	1,604	7,882	1,516	8,275
	143,346	**$ 312,920**	143,022	$ 312,097	142,901	$ 304,719

Other electric revenues, which are largely transmission-related revenues, for Montana-Dakota were $38.8 million, $23.0 million and $38.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.

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

	2019	2018	2017
North Dakota	**65%**	66%	66%
Montana	**22%**	20%	20%
Wyoming	**8%**	9%	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 are also 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 certain 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 North Dakota, Montana and South Dakota. These markets are highly seasonal and sales volumes depend largely on the weather. Additionally, the average customer consumption has tended to decline due to increases in energy efficient lighting and appliances being installed. The interconnected system consists of 15 electric generating units at 10 facilities and two small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 750,318 kW and total net ZRCs of 549.0 in 2019. For 2019, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 591.3. Montana-Dakota's planning reserve margin requirement within MISO was 537.2 ZRCs for 2019. 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. 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 two small portable diesel generators.

In June 2016, Montana-Dakota and a partner began construction on the BSSE project within the footprint of MISO. The project commenced on-line operations on February 5, 2019.

Additional energy is purchased as needed, or in lieu of generation if more economical, from the MISO market, and in 2019, Montana-Dakota purchased approximately 23 percent of its net kWh needs for its interconnected system through the MISO market.

Approximately 26 percent of the electricity delivered to customers from Montana-Dakota's owned generation in 2019 was from renewable resources. Although Montana-Dakota's generation resource capacity has increased to serve the needs of its customers, the carbon dioxide emission intensity of its electric generation resource fleet has been reduced by approximately 31 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 63,686 kW in July 2018. 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 also serves a portion of the needs of Montana-Dakota's Sheridan-area customers.

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

Generating Station	Type	Nameplate Rating (kW)	2019 ZRCs (a)	2019 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	90.9	501,394
Heskett	Steam	86,000	86.9	438,726
Heskett	Combustion Turbine	89,038	65.2	1,900
Glen Ullin	Heat Recovery	7,500	4.8	42,276
Cedar Hills	Wind	19,500	4.6	51,845
Diesel Units	Oil	3,650	3.8	4
Thunder Spirit	Wind	155,500	29.3	548,180
South Dakota:				
Big Stone (b)	Steam	94,111	105.8	656,783
Montana:				
Lewis & Clark	Steam	44,000	41.4	261,457
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	17.6	3,673
Glendive	Combustion Turbine	75,522	70.8	2,702
Miles City	Combustion Turbine	23,150	21.6	352
Diamond Willow	Wind	30,000	6.3	95,224
		750,318	549.0	2,604,516
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	188,254
		778,318	549.0	2,792,770

(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 2.3 million tons per contract year. For more information, see Item 8 - Note 20.

The owners of Big Stone Station, including Montana-Dakota, have a coal supply agreement with Peabody COALSALES, LLC to meet all of the Big Stone Station's fuel requirements for 2020. Montana-Dakota estimates the Big Stone Station coal supply agreement to be approximately 1.6 million tons for 2020.

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,	**2019**	2018	2017
Average cost of coal per MMBtu	**$ 2.15**	$ 2.00	$ 2.07
Average cost of coal per ton	**$ 31.36**	$ 29.08	$ 30.04

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 2020. In February 2019, Montana-Dakota announced that it intends to retire three aging coal-fired electric generating units. The retirements are expected to be completed in early 2021 for Lewis & Clark Station and early 2022 for units 1 and 2 at Heskett Station. Montana-Dakota also announced the intent to construct a new simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station. Future capacity that is needed to replace contracts, generation retirements 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 resulting from customer demands, technological advances and other factors 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, South Dakota and Wyoming, there are various recurring mechanisms with annual true-ups that can impact Montana-Dakota's results of operations, which also reflect monthly increases or decreases in electric fuel and purchased power costs (including demand charges). 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. Examples of these recurring mechanisms include: monthly Fuel and Purchased Power Tracking Adjustments, a fuel adjustment clause and an annual Electric Power Supply Cost Adjustment. 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 in Wyoming. For more information on regulatory assets and liabilities, see Item 8 - Note 7.

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 organizations serving parts of Montana-Dakota's system, 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 organizations serving parts of Montana-Dakota's system, along with certain of the transmission investments not recovered through retail rates. This tracking mechanism also has an annual true-up.

In Montana, Montana-Dakota recovers in rates, through a tracking mechanism, its allocated share of Montana property-related taxes assessed to electric operations on an after-tax basis.

For more information on regulatory matters, see Item 8 - Note 19.

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 Coyote Station was submitted timely to the North Dakota Department of Health in September 2017, with the permit issuance date not specified at this time. 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 issuance date not specified at this time. The Title V Operating Permit renewal application for Heskett Station was submitted timely in June 2019 to the North Dakota Department of Environmental Quality with the permit expected to be issued in 2020. The Title V Operating Permit renewal application for Lewis & Clark

Station was submitted timely in December 2019 to the Montana Department of Environmental Quality with the permit expected to be issued in 2020.

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

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

Montana-Dakota incurred $5.5 million of environmental capital expenditures in 2019, mainly for an embankment stabilization project at Lewis & Clark Station and coal ash management projects at Big Stone Station and Coyote Station. Environmental capital expenditures are estimated to be $700,000, $1.1 million and $3.3 million in 2020, 2021 and 2022, respectively, for various environmental projects, including coal ash impoundment closure project at Lewis & Clark Station. Montana-Dakota's capital and operational expenditures could also be affected by future environmental requirements, such as regional haze emissions reductions. For more information, see Item 1A - Risk Factors.

Natural Gas Distribution

General The Company's natural gas distribution segment is operated through its wholly owned subsidiary, MDU Energy Capital, which consists of operations from Montana-Dakota, Cascade and Intermountain. These companies sell natural gas at retail, serving 977,468 residential, commercial and industrial customers in 337 communities and adjacent rural areas across eight states as of December 31, 2019. They also provide natural gas transportation services to certain customers on the Company's systems. For more information on the retail customer classes served, see the table below. These services are provided through distribution systems aggregating approximately 20,300 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2019, the natural gas distribution operations' net natural gas distribution plant investment was $1.8 billion and its rate base was $1.2 billion.

The retail customers served and respective revenues by class for the natural gas distribution operations were as follows:

	2019		2018		2017	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
	(Dollars in thousands)					
Residential	**868,821**	**$ 479,673**	850,595	$ 464,697	833,255	$ 477,699
Commercial	**107,741**	**293,201**	106,297	279,566	104,795	283,899
Industrial	**906**	**26,570**	835	24,555	817	24,030
	977,468	**$ 799,444**	957,727	$ 768,818	938,867	$ 785,628

Transportation and other revenues for the natural gas distribution operations were $65.8 million, $54.4 million and $62.8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

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

	2019	2018	2017
Idaho	**29%**	30%	33%
Washington	**28%**	26%	26%
North Dakota	**15%**	15%	13%
Montana	**9%**	9%	9%
Oregon	**8%**	8%	8%
South Dakota	**6%**	7%	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, Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington and Wyoming. 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 later in Regulatory Matters. Additionally, the average customer consumption has tended to decline as more efficient appliances and furnaces are installed, and as the Company has implemented conservation programs. 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 resulting from customer demands, technological advances and other factors 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, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Enbridge Westcoast Pipeline, 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, Dominion Energy Questar Pipeline, LLC, Northwest Pipeline LLC, Northwest Natural Gas Company and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements, as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs through rate adjustments which are filed annually.

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

In Montana, Montana-Dakota recovers in rates, through a tracking mechanism, its allocated share of Montana property-related taxes assessed to natural gas operations on an after-tax basis.

In Minnesota and Washington, Great Plains and Cascade recover in rates, through a cost recovery tracking mechanism, qualifying capital investments related to the safety and integrity of its pipeline system.

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. Cascade initiated the required review by September 30, 2019, which resulted in a slight modification to the mechanism. The decoupling mechanism was approved to continue until January 1, 2025, with a review to be initiated by September 30, 2024.

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 in 2020.

On December 22, 2016, the MNPUC approved a request by Great Plains to implement a full revenue decoupling mechanism pilot project for three years. The decoupling mechanism will reflect the period January 1 through December 31. Great Plains requested approval to extend the initial pilot period through 2020 with a final determination to be made as part of its pending rate case.

For more information on regulatory matters, see Item 8 - Note 19.

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

The Company's natural gas distribution operations are very small-quantity generators of hazardous waste, and subject only to minimum regulation under the RCRA. Washington state rule defines Cascade as a small-quantity generator, but regulation under the rule is similar to 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 2019. 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 2022.

Montana-Dakota has ties to six historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Montana-Dakota is investigating possible soil and groundwater impacts due to the operation of two of these former manufactured gas plant sites. 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. To the extent not covered by insurance, Cascade will seek recovery of investigation and remediation costs through its natural gas rates charged to customers.

See Item 8 - Note 20 for further discussion of certain manufactured gas plant sites.

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 Minnesota, Montana, North Dakota, South Dakota and Wyoming. WBI Energy Transmission's 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 four 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, 2019, its net plant investment was $519.3 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.

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. Incremental supply from nontraditional sources, such as the Bakken area in Montana and North Dakota, have 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 continues to look for opportunities to increase transportation 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 194 Bcf of working gas capacity, 84 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 four 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 2019 represented 27 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, expiring in July 2035, with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements.

The nonregulated business competes for existing customers in the areas 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 subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations.

Administration of certain provisions of federal environmental laws has been delegated to the states where WBI Energy and its subsidiaries operate. Administering agencies may issue permits with varying terms and operational compliance conditions. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand, facility upgrades or modifications, and/or regulatory changes. The Company believes it is in substantial compliance with these regulations.

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 2019 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2022.

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, South Dakota, Texas, Washington and Wyoming. Knife River mines, processes and sells construction aggregates (crushed stone, sand and gravel); produces and sells asphalt mix; and supplies 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 its contracting services with its construction materials 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.

During 2019, Knife River purchased additional aggregate deposits in Texas and received a permit to construct a rock crushing plant at the quarry. Knife River also completed two business combinations of ready-mixed concrete suppliers headquartered in Idaho and Oregon. For more information on business combinations, see Item 8 - Note 3.

Knife River's backlog was approximately $693 million, $706 million and $486 million at December 31, 2019, 2018 and 2017, respectively. 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, 2019, during the next 12 months. For more information on backlog including the timing of revenue recognition, see Item 8 - Note 2.

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 approved by customers and (c) claims made against customers, which are determined to have a legal basis under existing contractual arrangements, and the amount for 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, or backlog estimates in general, 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 are also 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 978 million tons of the 1.1 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales, including estimated sales from acquired reserves prior to acquisition, from 2017 through 2019. 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, 2019, and sales for the years ended December 31, 2019, 2018 and 2017:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Production Area	owned	leased	owned	leased	**2019**	2018	2017			
Anchorage, AK	—	—	1	—	**868**	725	1,425	15,179	N/A	15
Hawaii	—	6	—	—	**1,680**	1,734	1,614	47,979	2020-2064	29
Northern CA	—	—	8	1	**1,901**	1,798	1,785	40,768	2028	22
Southern CA	—	2	—	—	**292**	356	55	90,910	2035	Over 100
Portland, OR	2	4	5	3	**4,868**	5,402	4,694	204,583	2025-2055	41
Eugene, OR	3	4	6	—	**1,205**	743	633	158,558	2021-2049	Over 100
Central OR/WA/ID	—	1	9	2	**2,700**	2,362	2,160	85,181	2028-2077	35
Southwest OR	5	5	10	6	**1,932**	2,395	2,367	107,098	2020-2053	48
Central MT	—	—	3	1	**822**	1,081	1,065	14,417	2023	15
Northwest MT	—	—	9	1	**2,084**	1,965	1,745	61,098	2020	32
Wyoming	—	—	—	2	**837**	626	613	8,762	2020-2026	13
Central MN	1	1	41	7	**3,477**	2,890	2,773	62,381	2020-2028	20 *
Northern MN	2	—	14	2	**330**	369	270	20,555	2020-2021	64
ND/SD	1	—	2	29	**3,747**	1,506	1,100	70,921	2020-2031	33 *
Texas	1	2	4	—	**1,378**	1,094	1,192	65,796	2022-2029	54
Sales from other sources					**4,193**	4,749	4,722			
					32,314	29,795	28,213	1,054,186		

* Includes estimate of three-year average sales for acquired reserves.

The 1.1 billion tons of estimated aggregate reserves at December 31, 2019, are comprised of 572 million tons on properties that are owned and 482 million tons that are leased. Approximately 38 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 21 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2017 through 2019 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 43 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:

	2019	2018	2017
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,014,431**	965,036	989,084
Acquisitions (a)	**71,157**	81,004	2,726
Sales volumes (b)	**(28,121)**	(25,046)	(23,491)
Other (c)	**(3,281)**	(6,563)	(3,283)
End of year	**1,054,186**	1,014,431	965,036

(a) Includes reserves from acquisitions of businesses.
(b) Excludes sales from other sources.
(c) 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 and tracked as they relate to the statuses of the 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 are also 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 are also subject to the RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs 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 has 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 are also 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 are also 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 considering 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 2019 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 2022.

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 20.

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 inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and 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. This segment also constructs and maintains renewable energy projects. These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

During 2019, MDU Construction Services purchased the assets of an electrical construction company in Redmond, Washington. For more information on business combinations, see Item 8 - Note 3.

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

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, 2019, MDU Construction Services owned or leased facilities in 16 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:

	2019	2018	2017
		(In millions)	
Inside specialty contracting	**$ 908**	$ 814	$ 625
Outside specialty contracting	**236**	125	83
	$ 1,144	$ 939	$ 708

The increase in backlog at December 31, 2019, compared to backlog at December 31, 2018, was largely attributable to the new project opportunities that MDU Construction Services continues to be awarded across its diverse operations, particularly inside specialty electrical and mechanical contracting in the hospitality, high-tech, mission critical and public industries. MDU Construction Services' outside power, communications and natural gas specialty contracting also have a high volume of available work. 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, 2019, during the next 12 months. Additionally, MDU Construction Services continues to further evaluate potential business combination opportunities that would be accretive to its business and grow its backlog. For more information on backlog including the timing of revenue recognition, see Item 8 - Note 2.

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 approved by customers, (c) change orders expected to receive confirmation in the ordinary course of business and (d) claims made against customers, which are determined to have a legal basis under existing contractual arrangements, and the amount for 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, or backlog estimates in general, at any point in time are predictive of future revenues.

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. MDU Construction Services expects bidding activity to remain strong for both inside and outside specialty construction companies in 2020. 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 quality and management of its workforce will enable it to effectively operate in this competitive environment.

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

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

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

MDU Construction Services did not incur any material environmental expenditures in 2019 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2022.

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 filed with the SEC. The factors and 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 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 investments and costs, financing, rate structures, customer service, health care coverage and costs, taxes, franchises; recovery of purchased power and purchased natural gas costs; and construction 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 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 that the Company's electric and natural gas transmission and distribution businesses' costs have been prudent, which could result in disallowance of costs. Also, the regulatory process for approving rates for these businesses may not allow for timely and full recovery of the costs of providing services or a return on the Company's invested capital. 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 regulators will allow full recovery of all remaining costs, which could leave 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 customers.

Approval from federal and state regulatory agencies would be needed for acquisition of the Company, as well as for certain acquisitions by the Company. The approval process could be lengthy and the outcome uncertain, which may deter potential acquirers from approaching the Company or impact the Company's ability to pursue 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 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 general economy. State and federal budget issues affect the funding available for infrastructure spending.

Economic conditions and population growth affect the electric and natural gas distribution businesses' growth in service territory, customer base and usage demand. Economic volatility in the markets served, along with economic conditions such as increased unemployment, which could impact the ability of the Company's customers to make payments, could adversely affect the Company's results of operations, cash flows and asset values. Further, any material decreases in customers' energy demand, 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, particularly those related to natural gas and electric transmission and distribution, include a variety of inherent hazards and operating risks, such as product leaks, explosions, mechanical failures, vandalism, fires, 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. A significant incident could also increase regulatory scrutiny and result in penalties and higher amounts of capital expenditures and operational costs. Losses not fully covered by insurance could have a material effect on the Company’s financial position, results of operations and cash flows.

A disruption of the regional electric transmission grid or interstate natural gas infrastructure could negatively impact the Company's business and reputation. Because the Company's electric and natural gas utility and pipeline systems are part of larger interconnecting systems, a disruption could result in a significant decrease in revenues and system repair costs, which could have a material impact on the Company's financial position, results of operations and cash flows.

The Company is subject to capital market and interest rate risks.
The Company's operations, particularly its electric and natural gas transmission and distribution businesses, require significant capital investment. Consequently, the Company relies on financing sources and capital markets as sources of liquidity for capital requirements not satisfied by its cash flows from operations. If the Company is not able to access capital at competitive rates, including through its current "at-the-market" offering program, the ability to implement its business plans, make capital expenditures or pursue acquisitions that the Company would otherwise rely on for future growth may be adversely affected. Market disruptions may increase the cost of borrowing or adversely affect the Company's ability to access one or more financial markets. Such disruptions could include:

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

The issuance of a substantial amount of the Company's common stock, whether issued in connection with an acquisition or otherwise, or the perception that such an issuance could occur, could have a dilutive effect on shareholders and/or may adversely affect the market price of the Company's common stock. Higher interest rates on borrowings could also have an adverse effect on the Company's operating results.

Financial market changes could impact the Company’s pension and postretirement benefit plans and obligations.
The Company has pension and postretirement defined benefit plans for some of its employees and former employees. Assumptions regarding future costs, returns on investments, interest rates and other actuarial assumptions have a significant impact on the funding requirements and expense recorded relating to these plans. Adverse changes in economic indicators, such as consumer spending, inflation data, interest rate changes, political developments and threats of terrorism, among other things, can create volatility in the financial markets which could change these assumptions and 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.

Significant changes in energy prices could negatively affect the Company's businesses.
Fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; supplies of domestic and foreign 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 oil and 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.

If oil and natural gas prices increase significantly, customer demand for utility, pipeline and midstream, and construction materials could decline, which could have a material impact on the Company's results of operations and cash flows. While the Company has fuel clause recovery mechanisms for its utility operations in most of the states in which it operates, higher utility fuel costs could significantly impact results of operations if such costs are not recovered. Delays in the collection of utility fuel cost recoveries, as compared to expenditures for fuel purchases, could have a negative impact on the Company's cash flows. High oil prices also affect the cost and demand for asphalt products and related contracting services. Low commodity prices could have a positive impact on sales but could negatively impact oil and natural gas production activities and subsequently the Company's pipeline and construction revenues in energy producing states in which the Company operates.

Reductions in the Company's credit ratings could increase financing costs.
There is no assurance 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. Events affecting the Company's financial results may impact its cash flows and credit metrics, potentially resulting in a change in the Company's credit ratings. 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.

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 quantities of large individual health care claims and an overall increase in total 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. 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 could also have indirect credit risk from participating 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.
Changes to federal, state and local 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.

The Company's operations could be negatively impacted by import tariffs and/or other government mandates.
The Company operates in or provides services to capital intensive industries in which federal trade policies could significantly impact the availability and cost of materials. Imposed and proposed tariffs could significantly increase the prices and delivery lead times on raw materials and finished products that are critical to the Company and its customers, such as aluminum and steel. Prolonged lead times on the delivery of raw materials and further tariff increases on raw materials and finished products could have a material adverse effect on the Company's business, financial condition and results of operations.

Operational Risks

Significant portions of the Company’s natural gas pipelines and power generation and transmission facilities are aging. The aging infrastructure may require significant additional maintenance or replacement that could adversely affect the Company’s results of operations.
The Company’s energy delivery infrastructure is aging, which increases certain risks, including breakdown or failure of equipment, pipeline leaks and fires developing from power lines. Aging infrastructure is more prone to failure which increases maintenance costs, unplanned outages and the need to replace facilities. Even if properly maintained, reliability may ultimately deteriorate and negatively affect the Company’s ability to serve its customers, which could result in increased costs associated with regulatory oversight. The costs associated with maintaining the aging infrastructure and capital expenditures for new or replacement infrastructure could cause rate volatility and/or regulatory lag in some jurisdictions. If, at the end of its life, the investment costs of a facility have not been fully recovered the Company may be adversely affected if commissions do not allow such costs to be recovered in rates. Such impacts of an aging infrastructure could have a material adverse effect on the Company’s results of operations and cash flows.

Additionally, hazards from aging infrastructure could result in serious injury, loss of human life, significant damage to property, environmental impacts, and impairment of operations, which in turn could lead to substantial losses. The location of facilities near populated areas, including residential areas, business centers, industrial sites, and other public gathering places, could increase the level of damages resulting from these risks. A major incident involving another natural gas system could lead to additional capital expenditures, increased regulation, and fines and penalties on natural gas utilities. The occurrence of any of these events could adversely affect the Company’s results of operations, financial position, and cash flows.

The Company's utility and pipeline operations are subject to planning risks.
Most electric and natural gas utility investments, including natural gas transmission pipeline investments, are made with the intent of being used for decades. In particular, electric transmission and generation resources are planned well in advance of when they are placed into service based upon resource plans using assumptions over the planning horizon; including sales growth, commodity prices, equipment and construction costs, regulatory treatment, available technology and public policy. Public policy changes and technology advancements related to areas such as energy efficient appliances and buildings, renewable and distributive electric generation and storage, carbon dioxide emissions, electric vehicle penetration, and natural gas availability and cost may significantly impact the planning assumptions. Changes in critical planning assumptions may result in excess generation, transmission and distribution resources creating increased per customer costs and downward pressure on load growth. These changes could also result in a stranded investment if the Company is unable to fully recover the costs of its investments.

The regulatory approval, permitting, construction, startup and/or operation of pipelines, power generation and transmission facilities, and aggregate reserves may involve unanticipated events, delays and unrecoverable costs.
The construction, startup and operation of natural gas pipelines and electric 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. Additionally, in a number of states in which the Company operates, it can be difficult to permit new aggregate sites or expand existing aggregate sites due to community resistance. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Operating or other costs required to comply with current or potential 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 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.

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.

Environmental and Regulatory Risks

The Company's operations could be adversely impacted by climate change.
Severe weather events, such as tornadoes, rain, ice and snowstorms and high and low temperature extremes, occur in regions in which the Company operates and maintains infrastructure. Climate change could change the frequency and severity of these weather events, which 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.

Severe weather events may damage or disrupt the Company's electric and natural gas transmission and distribution facilities, which could increase costs to repair facilities and restore service to customers. The cost of providing service could increase to the extent the frequency of severe 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, and potentially increase the cost of gas and the natural gas utility's ability to procure gas to meet customer demand. These changes could result in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction.

Increases in severe weather conditions or extreme temperature may cause infrastructure construction projects to be delayed or canceled and limit resources available for such projects resulting in decreased revenue or increased project costs at the construction materials and contracting and construction services businesses. In addition, drought conditions could restrict the availability of water supplies, inhibiting the ability of the construction businesses to conduct operations.

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 may require the Company to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather may result in decreased revenues. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature, 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 temperatures may create high energy demand and raise electricity prices, which could increase the cost of energy provided to customers.

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 some 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 insurance industry has also been adversely affected by severe weather events which may impact the availability of insurance coverage, insurance premiums and insurance policy terms.

The Company may also be subject to litigation related to climate change. Costs of such litigation could be significant, and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages, which could affect the Company's results of operations and cash flows if the costs are not recoverable in rates.

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 or taxes could impact the availability of goods and the 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, including air and water quality, wastewater discharge, the generation, transmission and disposal of solid waste and hazardous substances, aggregate permitting 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, permitting and environmental compliance for construction material facilities, natural gas gathering, and transmission and storage operations. Environmental laws and regulations can also require the Company to install pollution control equipment at its facilities, clean up spills and other contamination and correct environmental hazards, including payment of all or part of the cost to remediate sites where the Company's past activities, or the activities of other parties, caused environmental contamination. These laws and regulations generally require the Company to obtain and comply with a variety of environmental licenses, permits, inspections and other approvals and may cause the Company to shut down existing facilities due to difficulties in assuring compliance or where the cost of compliance makes operation of the facilities no longer economical. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome, financial or operational, of any such litigation or administrative proceedings.

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

Initiatives related to global climate change and to reduce GHG emissions could adversely impact the Company's operation, costs of or access to capital and impact or limit business plans.
Concern that GHG emissions are contributing to global climate change has led to international, federal, state and local 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 46 percent of Montana-Dakota's owned generating capacity and approximately 73 percent of the electricity it generated in 2019 was from coal-fired facilities.

Treaties, legislation or regulations to reduce GHG emissions in response to climate change may be adopted that affect the Company's utility operations by requiring additional energy conservation efforts or renewable energy sources, limiting emissions, imposing carbon taxes or other compliance costs; 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. Significant reductions in demand for the Company's utility services as a result of increased costs or emissions limitations could also 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.

There have also been recent efforts to influence the investment community to discourage investment in equity and debt securities of companies engaged in fossil fuel related business and pressuring lenders to limit funding to such companies. Additionally, some insurance carriers have indicated an unwillingness to insure assets and operations related to certain fossil fuels. Although the Company has not experienced difficulties in accessing the capital markets or insurance; such efforts, if successfully directed at the Company, could increase the costs of or access to capital and interfere with its business operations and ability to make capital expenditures.

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 weather normalization mechanisms in place. Where weather normalization 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 remediation costs. The Company could also be impacted by drought conditions, which may restrict the availability of water supplies and inhibit the ability of the construction businesses to conduct operations. As a result, unusually mild winters or summers or 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 competitive forces such 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 transportation and storage business. New acquisition opportunities are subject to competitive bidding environments which impact prices the Company must pay to successfully acquire new properties to grow its business. The Company's failure to effectively compete could negatively affect the Company's results of operations, financial position and cash flows.

The Company's operations may be negatively affected if it is unable to obtain, develop and retain key personnel and skilled labor forces.

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. At times of low unemployment, it can be difficult for the Company to attract and retain qualified and affordable personnel. A shortage in the supply of skilled personnel creates competitive hiring markets, increased labor expenses, decreased productivity and potentially lost business opportunities to support the Company's operating and growth strategies. Additionally, if the Company is unable to hire employees with the requisite skills, the Company may 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, retain and train the necessary skilled personnel and could negatively affect the Company's results of operations, financial position and cash flows.

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 is a holding company and relies on cash from its subsidiaries to pay dividends.

The Company is a holding company as a result of the Holding Company Reorganization in 2019. The Company's investments in its subsidiaries comprise the Company's primary assets. The Company depends on earnings, cash flows and dividends from its subsidiaries to pay dividends on its common stock. The Company's subsidiaries are separate legal entities that have no obligation to pay any amounts due on its obligations or to make funds available to pay dividends on common stock. Regulatory, contractual and legal limitations, as well as their capital requirements, affect the ability of the subsidiaries to pay dividends to the Company and thereby could restrict or influence the Company's ability or decision to pay dividends on its common stock, which could 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 25 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; newly-enacted government laws or regulations and the actual return on assets held in the plans; among others. The Company could experience increased operating expenses as a result of required contributions to MEPPs, which could 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. 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 uses technology in substantially all aspects of its business operations and requires 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, including disaster recovery and backup systems, due to hacking, human error, theft, sabotage, malicious software, acts of terrorism, acts of war, acts of nature or other causes. If these systems fail or become compromised, 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, any of which could have a material adverse effect on the Company's reputation, business, cash flows and results of operations or subject the Company to legal or regulatory liabilities and increased costs.

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 remediation costs that could 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 is subject to cyber security and privacy laws and regulations of many government agencies, including FERC and NERC. NERC issues comprehensive regulations and standards surrounding the security of bulk power systems and is continually in the process of updating these requirements, as well as establishing new requirements with which the utility industry must comply. As these regulations evolve, the Company will experience increased compliance costs and be at higher risk for violating these standards. Experiencing a cybersecurity incident could cause the Company to be non-compliant with applicable laws and regulations, causing the Company to incur costs related to legal claims or proceedings and regulatory fines or penalties. FERC continues its efforts to address cybersecurity challenges facing the nation's energy infrastructure. FERC has identified five areas of focus:

- Supply Chain/Insider Threat/Third-Party Authorized Access;
- Industry access to timely information on threats and vulnerabilities;
- Cloud/Managed Security Service Providers;
- Adequacy of security controls; and
- Internal network monitoring and detection.

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 and could go unnoticed for some time. In addition, there has been an increase in the number and sophistication of cyber-attacks across all industries worldwide and the threats are continually evolving. 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’s information systems experience on-going and often sophisticated cyber-attacks by a variety of sources with the apparent aim to breach the Company's cyber-defenses. As cyber-attacks continue to increase in frequency and sophistication, the Company may be unable to prevent all such attacks in the future. The Company is continuously reevaluating the need to upgrade and/or replace systems and network infrastructure. These upgrades and/or replacements could adversely impact operations by imposing substantial capital expenditures, creating delays or outages, or experiencing difficulties transitioning to new systems. Systems implementation disruption and any other information technology disruption, if not anticipated and appropriately mitigated, could have an adverse effect on the Company.

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 have a materially negative impact on the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities.
- Changes in operation, performance and construction of plant facilities or other assets.
- Changes in present or prospective generation.
- The availability of economic expansion or development opportunities.
- Population decline and demographic patterns.
- Economic and social impacts of epidemics.
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services.
- The cyclical nature of large construction projects at certain operations.
- Unanticipated project delays or changes in project costs, including related energy costs.
- Unanticipated changes in operating expenses or capital expenditures.
- Labor negotiations or disputes.

- Inability of the contract counterparties to meet their contractual obligations.
- Changes in accounting principles and/or the application of such principles to the Company.
- Changes in technology.
- Changes in legal or regulatory proceedings.
- Losses or costs relating to litigation.
- The inability 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 20, 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."

As of December 31, 2019, the Company's common stock was held by approximately 10,700 stockholders of record.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 29 consecutive years. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 12.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2019	—	—	—	—
November 1 through November 30, 2019	41,644	$29.16	—	—
December 1 through December 31, 2019	—	—	—	—
Total	41,644		—	—

(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.
(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

	2019	2018	2017	2016	2015	2014
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 351,725**	$ 335,123	$ 342,805	$ 322,356	$ 280,615	$ 277,874
Natural gas distribution	**865,222**	823,247	848,388	766,115	817,419	921,986
Pipeline and midstream	**140,444**	128,923	122,213	141,602	154,904	157,292
Construction materials and contracting	**2,190,717**	1,925,854	1,812,529	1,874,270	1,904,282	1,765,330
Construction services	**1,849,266**	1,371,453	1,367,602	1,073,272	926,427	1,119,529
Other	**16,551**	11,259	7,874	8,643	9,191	9,364
Intersegment eliminations	**(77,149)**	(64,307)	(58,060)	(57,430)	(78,786)	(136,302)
	$ 5,336,776	$ 4,531,552	$ 4,443,351	$ 4,128,828	$ 4,014,052	$ 4,115,073
Operating income (loss) (000's):						
Electric	**$ 64,039**	$ 65,148	$ 79,902	$ 67,929	$ 59,915	$ 61,515
Natural gas distribution	**69,188**	72,336	84,239	66,166	54,974	68,185
Pipeline and midstream	**42,796**	36,128	36,004	42,864	30,218	46,500
Construction materials and contracting	**179,955**	141,426	143,230	178,753	148,312	87,243
Construction services	**126,426**	86,764	81,292	53,546	43,678	82,408
Other	**(1,184)**	(79)	(619)	(349)	(8,414)	(5,370)
Intersegment eliminations	**—**	—	—	—	(2,942)	(9,900)
	$ 481,220	$ 401,723	$ 424,048	$ 408,909	$ 325,741	$ 330,581
Earnings (loss) on common stock (000's):						
Electric	**$ 54,763**	$ 47,000	$ 49,366	$ 42,222	$ 35,914	$ 36,731
Natural gas distribution	**39,517**	37,732	32,225	27,102	23,607	30,484
Pipeline and midstream	**29,603**	28,459	20,493	23,435	13,250	24,666
Construction materials and contracting	**120,371**	92,647	123,398	102,687	89,096	51,510
Construction services	**92,998**	64,309	53,306	33,945	23,762	54,432
Other	**(2,086)**	(761)	(1,422)	(3,231)	(14,941)	(7,386)
Intersegment eliminations	**—**	—	6,849	6,251	5,016	(6,095)
Earnings on common stock before income (loss) from discontinued operations	**335,166**	269,386	284,215	232,411	175,704	184,342
Income (loss) from discontinued operations, net of tax*	**287**	2,932	(3,783)	(300,354)	(834,080)	109,311
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	—	(131,691)	(35,256)	(3,895)
	$ 335,453	$ 272,318	$ 280,432	$ 63,748	$ (623,120)	$ 297,548
Earnings per common share before discontinued operations - diluted	**$ 1.69**	$ 1.38	$ 1.45	$ 1.19	$ .90	$ .96
Discontinued operations attributable to the Company, net of tax	**—**	.01	(.02)	(.86)	(4.10)	.59
	$ 1.69	$ 1.39	$ 1.43	$ .33	$ (3.20)	$ 1.55
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	**198,626**	196,150	195,687	195,618	194,986	192,587
Dividends declared per common share	**$ .8150**	$ .7950	$ .7750	$ .7550	$ .7350	$ .7150
Book value per common share	**$ 14.21**	$ 13.09	$ 12.44	$ 11.78	$ 12.83	$ 16.66
Market price per common share (year end)	**$ 29.71**	$ 23.84	$ 26.88	$ 28.77	$ 18.32	$ 23.50
Market price ratios:						
Dividend payout**	**48%**	58%	53%	63%	82%	74%
Yield	**2.8%**	3.4%	2.9%	2.7%	4.1%	3.1%
Market value as a percent of book value	**209.1%**	182.1%	216.1%	244.2%	142.8%	141.1%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) in 2015 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.

Item 6. Selected Financial Data (continued)

	2019	2018	2017	2016	2015	2014
General						
Total assets (000's)	**$ 7,683,059**	$ 6,988,110	$ 6,334,666	$ 6,284,467	$ 6,565,154	$ 7,805,405
Total long-term debt (000's)	**$ 2,243,107**	$ 2,108,695	$ 1,714,853	$ 1,790,159	$ 1,796,163	$ 2,016,198
Capitalization ratios:						
Total equity	**56%**	55%	59%	56%	58%	62%
Total debt	**44**	45	41	44	42	38
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,314,307**	3,354,401	3,306,470	3,258,537	3,316,017	3,308,358
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**591.3**	574.5	553.1	559.7	547.3	584.0
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	**537.2**	537.2	530.2	559.7	547.3	522.4
All-time demand peak - kW (Interconnected system)	**611,542**	611,542	611,542	611,542	611,542	582,083
Electricity produced (thousand kWh)	**2,792,770**	2,840,353	2,630,640	2,626,763	1,898,160	2,519,938
Electricity purchased (thousand kWh)	**891,539**	831,039	955,687	904,702	1,658,002	1,010,422
Average cost of electric fuel and purchased power per kWh	**$ .023**	$ .022	$ .022	$ .021	$ .024	$ .025
Natural Gas Distribution						
Retail sales (Mdk)	**123,675**	112,566	112,551	99,296	95,559	104,297
Transportation sales (Mdk)	**166,077**	149,497	144,477	147,592	154,225	145,941
Pipeline and Midstream						
Transportation (Mdk)	**429,660**	351,498	312,520	285,254	290,494	233,483
Gathering (Mdk)	**13,900**	14,882	16,064	20,049	33,441	38,372
Customer natural gas storage balance (Mdk)	**16,223**	13,928	22,397	26,403	16,600	14,885
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**32,314**	29,795	28,213	27,580	26,959	25,827
Asphalt (tons)	**6,707**	6,838	6,237	7,203	6,705	6,070
Ready-mixed concrete (cubic yards)	**4,123**	3,518	3,548	3,655	3,592	3,460
Aggregate reserves (000's tons)	**1,054,186**	1,014,431	965,036	989,084	1,022,513	1,061,156

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

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota becoming a subsidiary of the Company. The merger was conducted pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the stockholders of the constituent corporation. Immediately after consummation of the Holding Company Reorganization, the Company had, on a consolidated basis, the same assets, businesses and operations as Montana-Dakota had immediately prior to the consummation of the Holding Company Reorganization. As a result of the Holding Company Reorganization, the Company became the successor issuer to Montana-Dakota pursuant to Rule 12g-3(a) of the Exchange Act, and as a result, the Company's common stock was deemed registered under Section 12(b) of the Exchange Act.

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-mixed 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 business 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.

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.

Consolidated Earnings Overview

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

Years ended December 31,	**2019**	2018	2017
	(In millions, except per share amounts)		
Electric	**$ 54.8**	$ 47.0	$ 49.4
Natural gas distribution	**39.5**	37.7	32.2
Pipeline and midstream	**29.6**	28.5	20.5
Construction materials and contracting	**120.4**	92.6	123.4
Construction services	**93.0**	64.3	53.3
Other	**(2.1)**	(.7)	(1.5)
Intersegment eliminations	**—**	—	6.9
Earnings before discontinued operations	**335.2**	269.4	284.2
Income (loss) from discontinued operations, net of tax	**.3**	2.9	(3.8)
Earnings on common stock	**$ 335.5**	$ 272.3	$ 280.4
Earnings per common share - basic:			
Earnings before discontinued operations	**$ 1.69**	$ 1.38	$ 1.46
Discontinued operations, net of tax	**—**	.01	(.02)
Earnings per common share - basic	**$ 1.69**	$ 1.39	$ 1.44
Earnings per common share - diluted:			
Earnings before discontinued operations	**$ 1.69**	$ 1.38	$ 1.45
Discontinued operations, net of tax	**—**	.01	(.02)
Earnings per common share - diluted	**$ 1.69**	$ 1.39	$ 1.43

2019 compared to 2018 The Company's consolidated earnings increased $63.2 million.

Positively impacting the Company's earnings was an increase in gross margin at the construction services business, largely resulting from higher inside and outside specialty contracting workloads. Also contributing to the increase in earnings was an increase in gross margin at the construction materials and contracting business as a result of strong economic environments in certain states, as well as contributions from the businesses acquired and an increase in gains recognized on asset sales. The electric business also positively impacted earnings primarily due to approved rate relief in Montana and recovery of the investment in the BSSE project placed into service in the first quarter of 2019. Higher returns on the Company's benefit plan investments also increased earnings across all businesses. At the pipeline and midstream business, increased rates and volumes of natural gas being transported through its pipeline were mostly offset by the absence of a $4.2 million income tax benefit included in 2018, as discussed below, and higher depreciation, depletion and amortization expense.

2018 compared to 2017 The Company's consolidated earnings decreased $8.1 million.

The Company's earnings were positively impacted in 2018 as a result of the lower federal statutory tax rate, which was partially offset by the absence of a $39.5 million tax benefit recorded in the fourth quarter of 2017 for the revaluation of the business's net deferred tax liabilities. Both tax impacts were the result of the enactment of the TCJA, as further discussed in Item 8 - Note 14. Decreased earnings due to lower returns on investments also offset the lower income tax rate. Also positively impacting the Company's earnings were higher outside specialty contracting gross margins due to increased outside equipment sales and rentals at the construction services business, as well as a $4.2 million income tax benefit relating to the reversal of a regulatory liability recorded in 2017 based on a FERC final accounting order issued during the third quarter of 2018 at the pipeline and midstream business.

A discussion of key financial data from the Company's business segments follows.

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." For more information, see Part I - 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 16.

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, employee satisfaction, customer service and shareholder return, while continuing to focus on providing safe, environmentally friendly, reliable and competitively priced energy and related services to customers. The Company is focused on cultivating organic growth while managing operating costs and 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, transmission and distribution and natural gas systems, and through selected acquisitions of companies and properties with similar operating and growth objectives 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, weather, competitive factors in the energy industry, population growth 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, environmental and system integrity regulations. To assist in the reduction of regulatory lag with the increase in investments, tracking mechanisms have been implemented in certain jurisdictions, as further discussed in Items 1 and 2 - Business Properties and Item 8 - Note 19. The Pipeline and Hazardous Materials Safety Administration recently issued additional rules to strengthen the safety of natural gas transmission and hazardous liquid pipelines. The Company is currently evaluating the first phase of the rules. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas, as well as increase costs to produce electricity and natural gas. The segments continue to invest in facility upgrades to be in compliance with the existing and future regulations.

Tariff increases on steel and aluminum materials could negatively affect the segments' construction projects and maintenance work. The Company continues to monitor the impact of tariffs on raw material costs. The natural gas distribution segment is also facing increased lead times on delivery of certain raw materials used in pipeline projects. In addition to the effect of tariffs, long lead times are attributable to increased demand for steel products from pipeline companies as they respond to the United States Department of Transportation Pipeline System Safety and Integrity Plan. The Company continues to monitor the material lead times and is working with manufacturers to proactively order such materials to help mitigate the risk of delays due to extended lead times.

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 costs and lead times, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will likely 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 both electric and natural gas customers has tended to decline as more efficient appliances and furnaces are installed, and as the Company has implemented conservation programs. Natural gas 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 on the Company's distribution margins.

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

Years ended December 31,	**2019**	2018	2017
	(Dollars in millions, where applicable)		
Operating revenues	**$ 351.7**	$ 335.1	$ 342.8
Electric fuel and purchased power	**86.6**	80.7	78.7
Taxes, other than income	**.6**	.7	.8
Adjusted gross margin	**264.5**	253.7	263.3
Operating expenses:			
Operation and maintenance	**125.7**	123.0	122.2
Depreciation, depletion and amortization	**58.7**	51.0	47.7
Taxes, other than income	**16.1**	14.5	13.5
Total operating expenses	**200.5**	188.5	183.4
Operating income	**64.0**	65.2	79.9
Other income	**3.4**	1.2	3.2
Interest expense	**25.3**	25.9	25.4
Income before income taxes	**42.1**	40.5	57.7
Income taxes	**(12.7)**	(6.5)	7.7
Net income	**54.8**	47.0	50.0
Loss/dividends on preferred stock	**—**	—	.6
Earnings	**$ 54.8**	$ 47.0	$ 49.4
Retail sales (million kWh):			
Residential	**1,177.9**	1,196.6	1,153.5
Commercial	**1,499.9**	1,513.9	1,513.1
Industrial	**549.4**	551.0	539.9
Other	**87.1**	92.9	100.0
	3,314.3	3,354.4	3,306.5
Average cost of electric fuel and purchased power per kWh	**$ .023**	$ .022	$ .022

Adjusted gross margin is a non-GAAP financial measure. For additional information and reconciliation of the non-GAAP adjusted gross margin attributable to the electric segment, see the Non-GAAP Financial Measures section later in this Item.

2019 compared to 2018 Electric earnings increased $7.8 million (17 percent) as a result of:

Adjusted gross margin: Increase of $10.8 million, primarily due to an increase in revenues. The revenue increase was driven by implemented regulatory mechanisms, which include approved Montana interim and final rates and recovery of the investment in the

BSSE project placed into service in the first quarter of 2019. Also contributing to the increase was the absence in 2019 of a transmission formula rate adjustment recognized in the third quarter of 2018 for decreased costs on the BSSE project. These increases were partially offset by lower retail sales volumes of 1.2 percent across all major customer classes.

Operation and maintenance: Increase of $2.7 million, primarily resulting from higher payroll-related costs, partially offset by lower material expenses across all locations.

Depreciation, depletion and amortization: Increase of $7.7 million as a result of increased property, plant and equipment balances including the BSSE project, as previously discussed, and other capital projects, as well as a reserve for certain costs related to the retirement of three aging coal-fired electric generating units, as discussed in Item 8 - Note 7, which is offset in income taxes.

Taxes, other than income: Increase of $1.6 million, primarily from higher property taxes in certain jurisdictions.

Other income: Increase of $2.2 million, largely the result of higher returns on the Company's benefit plan investments, partially offset by the write-down of a non-utility investment, as discussed in Item 8 - Note 8.

Interest expense: Decrease of $600,000 driven by higher AFUDC, which resulted in more interest being capitalized on regulated construction projects.

Income taxes: Increase in income tax benefits of $6.2 million, largely due to increased production tax credits, as well as increased excess deferred tax amortization.

2018 compared to 2017 Electric earnings decreased $2.4 million (5 percent) as a result of:

Adjusted gross margin: Decrease of $9.6 million, primarily due to lower operating revenues driven by the reserves against revenues in certain jurisdictions for anticipated refunds to customers for lower income taxes due to the enactment of TCJA and a transmission formula rate adjustment due to lower than anticipated project costs on the BSSE project recorded in the third quarter of 2018. Partially offsetting the decreases to adjusted gross margin were the absence in 2018 of reserves related to tracker balances in prior years and increased retail sales volumes of 1 percent to all major customer classes.

Operation and maintenance: Increase of $800,000, largely from higher contract services at certain generating stations. Partially offsetting the increase were lower payroll-related costs.

Depreciation, depletion and amortization: Increase of $3.3 million as a result of increased plant balances.

Taxes, other than income: Increase of $1.0 million, primarily from higher property taxes in certain jurisdictions.

Other income: Decrease of $2.0 million, largely the result of lower returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $14.2 million, largely due to the enactment of the TCJA reduced corporate tax rate, reduced income before income taxes and the absence of $2.1 million of income tax expense in 2018 for the revaluation of nonutility net deferred tax assets in 2017. Partially offsetting these decreases were lower production tax credits. A portion of the reduction in income taxes are being reserved against revenues, as previously discussed, resulting in a minimal impact on overall earnings.

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

Years ended December 31,	2019	2018	2017
	(Dollars in millions, where applicable)		
Operating revenues	**$ 865.2**	$ 823.2	$ 848.4
Purchased natural gas sold	**477.6**	454.8	479.9
Taxes, other than income	**30.3**	28.5	30.0
Adjusted gross margin	**357.3**	339.9	338.5
Operating expenses:			
Operation and maintenance	**185.0**	173.4	164.3
Depreciation, depletion and amortization	**79.6**	72.5	69.4
Taxes, other than income	**23.5**	21.7	20.5
Total operating expenses	**288.1**	267.6	254.2
Operating income	**69.2**	72.3	84.3
Other income	**7.2**	.2	2.0
Interest expense	**35.5**	30.7	31.2
Income before income taxes	**40.9**	41.8	55.1
Income taxes	**1.4**	4.1	22.8
Net income	**39.5**	37.7	32.3
Loss/dividends on preferred stock	**—**	—	.1
Earnings	**$ 39.5**	$ 37.7	$ 32.2
Volumes (MMdk)			
Retail sales:			
Residential	**69.4**	63.7	63.6
Commercial	**49.1**	44.4	44.3
Industrial	**5.2**	4.5	4.6
	123.7	112.6	112.5
Transportation sales:			
Commercial	**2.2**	2.2	2.0
Industrial	**163.9**	147.3	142.5
	166.1	149.5	144.5
Total throughput	**289.8**	262.1	257.0
Average cost of natural gas per dk	**$ 3.86**	$ 4.04	$ 4.26

Adjusted gross margin is a non-GAAP financial measure. For additional information and reconciliation of the non-GAAP adjusted gross margin attributable to the natural gas distribution segment, see the Non-GAAP Financial Measures section later in this Item.

2019 compared to 2018 Natural gas distribution earnings increased $1.8 million (5 percent) as a result of:

Adjusted gross margin: Increase of $17.4 million, primarily driven by an increase in retail sales volumes of 9.9 percent related to all customer classes due to colder weather, partially offset by weather normalization and conservation adjustments in certain jurisdictions, and approved rate recovery in certain jurisdictions. The adjusted gross margin was also positively impacted by higher rate realization due to higher conservation revenue, which offsets the conservation expense in operation and maintenance expense.

Operation and maintenance: Increase of $11.6 million, largely related to higher payroll-related costs, as well as higher conservation expenses being recovered in revenue. The increase was partially offset by lower contract services, which includes the absence of the prior year's recognition of a non-recurring expense related to the approved WUTC general rate case settlement in the second quarter 2018.

Depreciation, depletion and amortization: Increase of $7.1 million, primarily as a result of increased property, plant and equipment balances.

Taxes, other than income: Increase of $1.8 million due to higher property taxes in certain jurisdictions and increased payroll taxes.

Other income: Increase of $7.0 million, largely resulting from higher returns on the Company's benefit plan investments and increased interest income related to higher gas costs to be collected from customers, as discussed in Item 8 - Note 19. Partially offsetting these increases was a write-down of a non-utility investment, as discussed in Item 8 - Note 8.

Interest expense: Increase of $4.8 million, largely resulting from increased debt balances to finance higher gas costs to be collected from customers, as discussed in Item 8 - Note 19.

Income taxes: Decrease of $2.7 million, largely due to increased permanent tax benefits related to the Company's benefit plan investments.

2018 compared to 2017 Natural gas distribution earnings increased $5.5 million (17 percent) as a result of:

Adjusted gross margin: Increase of $1.4 million, primarily due to increased retail sales margins, mainly the result of weather normalization mechanisms in certain jurisdictions and conservation revenue, which offsets the conservation expense in operation and maintenance expense. Also contributing to the retail sales margin increase were higher basic service charges as a result of increased retail sales customers and rate design. These increases were partially offset by tax reform revenue impacts for refunds to customers as a result of lower income taxes due to the enactment of TCJA and lower volumes in certain jurisdictions.

Operation and maintenance: Increase of $9.1 million, largely related to conservation expenses being recovered in revenue; contract services, which includes the recognition of a non-recurring expense related to the approved WUTC general rate case settlement in the second quarter 2018; and higher payroll-related costs.

Depreciation, depletion and amortization: Increase of $3.1 million, primarily as a result of increased plant balances offset in part by lower depreciation rates implemented in certain jurisdictions.

Taxes, other than income: Increase of $1.2 million due to higher property taxes in certain jurisdictions.

Other income: Decrease of $1.8 million, primarily the result of lower returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $18.7 million, largely due to the enactment of the TCJA reduced corporate tax rate, as well as the absence of $4.3 million income tax expense related to the 2017 revaluation of nonutility net deferred tax assets, and reduced income before income taxes. A portion of the reduction in income taxes are being reserved against revenues or passed back to customers, as previously discussed, resulting in a minimal impact on overall earnings.

Outlook The Company expects these segments will grow rate base by approximately 5 percent annually over the next five years on a compound basis. 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 and replacement electric generation and transmission and natural gas systems.

In February 2019, the Company announced that it intends to retire three aging coal-fired electric generating units, resulting from the Company's analysis showing that the plants are no longer expected to be cost competitive for customers. The retirements are expected to be in early 2021 for Lewis & Clark Station in Sidney, Montana, and in early 2022 for units 1 and 2 at Heskett Station in Mandan, North Dakota. In addition, the Company announced that it intends to construct Heskett Unit 4, an 88-MW simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station near Mandan, North Dakota. Heskett Unit 4 production costs coupled with the MISO market purchases are expected to be about half the total cost of continuing to run the coal-fired electric generating units at Heskett and Lewis & Clark stations. Heskett Unit 4 was included in the Company's recently submitted integrated resource plan. On August 28, 2019, the Company filed for an advanced determination of prudence with the NDPSC for Heskett Unit 4. If approved, Heskett Unit 4 is expected to be placed into service in 2023. The Company filed requests for the usage of deferred accounting for the costs related to the retirement of Lewis & Clark Station and units 1 and 2 at Heskett Station with the NDPSC on September 16, 2019, the MTPSC on November 1, 2019 and the SDPUC on November 8, 2019. The SDPUC approved the use of deferred accounting as requested on January 7, 2020.

The Company continues to be focused on the regulatory recovery of its investments. 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 19.

Pipeline and Midstream

Strategy and challenges The 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, operating 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; and expansion of energy-related services leveraging on its core competencies. In support of this strategy, the Company completed and placed into service the following projects in 2019 and 2018:

- In November 2019, Phase I of the Line Section 22 Expansion project in the Billings, Montana, area increased capacity by 14.3 MMcf per day.
- In September 2019, the Demicks Lake project in McKenzie County, North Dakota, increased capacity by 175 MMcf per day.
- In November 2018, the Valley Expansion project in eastern North Dakota and far western Minnesota increased capacity by 40 MMcf per day.
- In September 2018, the Line Section 27 Expansion project in the Bakken area of northwestern North Dakota increased capacity by over 200 MMcf per day and brought the total capacity of Line Section 27 to over 600 MMcf per day.

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.

Tariff increases on steel and aluminum materials could negatively affect the segment's construction projects and maintenance work. The Company continues to monitor the impact of tariffs on raw material costs. The segment experiences extended lead times on raw materials that are critical to the segment's construction and maintenance work. Long lead times on materials could delay maintenance work and project construction potentially causing lost revenues and/or increased costs. The Company continues to proactively monitor and plan for the material lead times, as well as work with manufacturers and suppliers to help mitigate the risk of delays due to extended lead times.

The pipeline and midstream segment is subject to extensive regulation including certain operational, environmental and system integrity regulations, as well as various permit terms and operational compliance conditions. The Pipeline and Hazardous Materials Safety Administration recently issued additional rules to strengthen the safety of natural gas transmission and storage facilities and hazardous liquid pipelines. The Company is currently evaluating the first phase of the rules. 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 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 - The following information summarizes the performance of the pipeline and midstream segment.

Years ended December 31,	2019	2018	2017
	(Dollars in millions)		
Operating revenues	**$ 140.4**	$ 128.9	$ 122.2
Operating expenses:			
Operation and maintenance	**63.1**	62.2	56.9
Depreciation, depletion and amortization	**21.2**	17.9	16.8
Taxes, other than income	**13.3**	12.7	12.5
Total operating expenses	**97.6**	92.8	86.2
Operating income	**42.8**	36.1	36.0
Other income	**1.2**	1.0	1.8
Interest expense	**7.2**	5.9	5.0
Income before income taxes	**36.8**	31.2	32.8
Income taxes	**7.2**	2.7	12.3
Net income	**$ 29.6**	$ 28.5	$ 20.5
Transportation volumes (MMdk)	**429.7**	351.5	312.5
Natural gas gathering volumes (MMdk)	**13.9**	14.9	16.1
Customer natural gas storage balance (MMdk):			
Beginning of period	**13.9**	22.4	26.4
Net injection (withdrawal)	**2.3**	(8.5)	(4.0)
End of period	**16.2**	13.9	22.4

2019 compared to 2018 Pipeline and midstream earnings increased $1.1 million (4 percent) as a result of:

Revenues: Increase of $11.5 million, largely attributable to increased volumes of natural gas transported through its system as a result of organic growth projects, as previously discussed in Strategy and challenges, and increased rates effective May 1, 2019, due to the FERC rate case finalized in September 2019.

Operation and maintenance: Increase of $900,000, primarily from higher payroll-related costs and materials costs.

Depreciation, depletion and amortization: Increase of $3.3 million, primarily due to increased property, plant and equipment balances, largely the result of organic growth projects that have been placed into service, and higher depreciation rates effective May 1, 2019, due to the FERC rate case finalized in September 2019.

Taxes, other than income: Increase of $600,000 driven by higher property taxes in certain jurisdictions.

Other income: Comparable to the prior year.

Interest expense: Increase of $1.3 million, largely resulting from higher debt balances to finance organic growth projects, as previously discussed.

Income taxes: Increase of $4.5 million, primarily driven by the absence in 2019 of a $4.2 million income tax benefit, as discussed later.

2018 compared to 2017 Pipeline and midstream earnings increased $8.0 million (39 percent) as a result of:

Revenues: Increase of $6.7 million, largely attributable to increased volumes of natural gas transported through its system as a result of completed organic growth projects, as previously discussed in Strategy and challenges, and higher nonregulated project workloads, which increased revenues $4.1 million. These increases were partially offset by decreased storage-related revenues reflecting the decrease in natural gas pricing spreads, as discussed in the Outlook section.

Operation and maintenance: Increase of $5.3 million, primarily from higher nonregulated project costs of $3.9 million directly related to the increase in nonregulated project workloads, as previously discussed, as well as higher professional services, material costs and contract services.

Depreciation, depletion and amortization: Increase of $1.1 million, largely resulting from organic growth projects.

Taxes, other than income: Comparable to the prior year.

Other income: Decrease of $800,000, primarily the result of lower returns on investments partially offset by higher AFUDC.

Interest expense: Increase of $900,000, largely resulting from higher debt balances.

Income taxes: Decrease of $9.6 million, primarily resulting from the lower corporate tax rate due to the enactment of the TCJA creating a reduction to income tax expense, as well as the realization of a $4.2 million income tax benefit related to the reversal of a regulatory liability recorded in 2017 based on a FERC final accounting order issued during third quarter of 2018.

Outlook The Company has continued to experience the effects of natural gas production at record levels, which has provided opportunities for organic growth projects and increased demand. The completion of organic growth projects has contributed to the Company transporting increasing volumes of natural gas through its system. The record levels of natural gas supply have moderated the need for storage services and put downward pressure on natural gas prices and minimized pricing volatility. Both natural gas production levels and pressure on natural gas prices are expected to continue 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 current growth projects.

The Company began construction on the Line Section 22 Expansion project in the Billings, Montana, area in May 2019. Phase I of the project was placed into service in November 2019, as previously discussed. Phase II has an expected in-service date in the first quarter of 2020 and is designed to increase capacity by 8.2 MMcf per day to serve incremental demand in Billings, Montana. The Company has signed long-term contracts supporting the project.

The Company began construction on the Demicks Lake Expansion project, located in McKenzie County, North Dakota, in November 2019. In February 2020, the Company completed and placed the project into service. The Company has signed a long-term contract supporting this project, which increased capacity by 175 MMcf per day.

In January 2019, the Company announced the North Bakken Expansion project, which includes construction of a new pipeline, compression and ancillary facilities to transport natural gas from core Bakken production areas near Tioga, North Dakota, to a new connection with Northern Border Pipeline in McKenzie County, North Dakota. The Company's long-term customer commitments and anticipated incremental commitments with the continuing record levels of natural gas production in the Bakken region support the project at a design capacity of 350 MMcf per day. Construction is expected to begin in early 2021 with an estimated completion date late in 2021, which is dependent on regulatory and environmental permitting. On June 28, 2019, the Company filed with the FERC a request to initiate the National Environmental Policy Act pre-filing process and received FERC approval of the pre-filing request on July 3, 2019.

In December 2019, the Company entered into a purchase and sale agreement with Scout Energy Group II, LP to divest of its regulated gathering assets located in Montana and North Dakota, which includes approximately 400 miles of natural gas gathering pipelines and associated compression and ancillary facilities. On January 8, 2020, the Company filed an application with the FERC to authorize abandonment by sale of the gathering assets. The sale is expected to close in the first half of 2020 with an effective date of January 1, 2020, pending approval by the FERC.

Construction Materials and Contracting

Strategy and challenges The construction materials and contracting segment provides an integrated set of aggregate-based 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 Company's acquisition activity supports this strategy.

As one of the country's largest sand and gravel producers, the segment continues to strategically manage its approximately 1.1 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 Company's aggregate reserves are naturally declining and as a result, the Company seeks acquisition opportunities to replace the reserves. In the first quarter of 2019, the Company purchased additional aggregate deposits in Texas that are estimated to contain a 40-year supply of high-quality aggregates. Also during 2019, the Company increased aggregate reserves by approximately 40 million tons largely due to strategic asset purchases.

The construction materials and contracting segment faces challenges that are not under the direct control of the business. The segment operates in geographically diverse and highly competitive markets. Competition can put negative pressure on the segment's operating margins. The segment is also subject to volatility in the cost of raw materials such as diesel fuel, gasoline, liquid asphalt, cement and steel. Although it is difficult to determine the split between inflation and supply/demand increases, diesel fuel costs remained fairly stable in

2019, while asphalt oil costs trended higher in 2019 as compared to 2018. 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 and governmental infrastructure spending.

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 continues to face increasing pressure to control costs, as well as find and train a skilled workforce to meet the needs of increasing demand and seasonal work.

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

Years ended December 31,	2019	2018	2017
	(Dollars in millions)		
Operating revenues	**$ 2,190.7**	$ 1,925.9	$ 1,812.5
Cost of sales:			
Operation and maintenance	**1,798.3**	1,601.7	1,500.1
Depreciation, depletion and amortization	**74.3**	59.0	52.5
Taxes, other than income	**44.1**	39.7	38.0
Total cost of sales	**1,916.7**	1,700.4	1,590.6
Gross margin	**274.0**	225.5	221.9
Selling, general and administrative expense:			
Operation and maintenance	**86.3**	77.6	71.5
Depreciation, depletion and amortization	**3.1**	2.2	3.4
Taxes, other than income	**4.6**	4.3	3.8
Total selling, general and administrative expense	**94.0**	84.1	78.7
Operating income	**180.0**	141.4	143.2
Other income (expense)	**1.6**	(3.1)	.4
Interest expense	**23.8**	17.3	14.8
Income before income taxes	**157.8**	121.0	128.8
Income taxes	**37.4**	28.4	5.4
Net income	**$ 120.4**	$ 92.6	$ 123.4
Sales (000's):			
Aggregates (tons)	**32,314**	29,795	28,213
Asphalt (tons)	**6,707**	6,838	6,237
Ready-mixed concrete (cubic yards)	**4,123**	3,518	3,548

2019 compared to 2018 Construction materials and contracting's earnings increased $27.8 million (30 percent) as a result of:

Revenues: Increase of $264.8 million driven by higher contracting services and material sales due to strong economic environments in certain states, as well as additional material volumes associated with the businesses acquired.

Gross margin: Increase of $48.5 million, largely resulting from higher revenues due to strong economic environments in certain states, as previously discussed, higher contracting bid margins and higher realized material prices. Also contributing to the increased gross margin was an increase in gains on asset sales in certain regions of approximately $7.5 million.

Selling, general and administrative expense: Increase of $9.9 million, primarily related to the businesses acquired and higher payroll-related costs.

Other income (expense): Increased income of $4.7 million, largely the result of higher returns on the Company's benefit plan investments.

Interest expense: Increase of $6.5 million, largely resulting from higher debt balances as a result of recent acquisitions, capital expenditures and higher average interest rates.

Income taxes: Increase of $9.0 million directly resulting from an increase in income before taxes.

2018 compared to 2017 Construction materials and contracting's earnings decreased $30.8 million (25 percent) as a result of:

Revenues: Increase of $113.4 million driven by higher asphalt product and aggregate volumes due to increased agency demand, increased realized prices and lower material costs. Partially offsetting these increases were lower ready-mixed concrete volumes due to a decrease in available work and unfavorable weather conditions in certain regions.

Gross margin: Increase of $3.6 million resulting from higher asphalt product volumes and margins, largely from recent acquisitions and higher realized prices. Also contributing to the increase were higher aggregate volumes and margins due to strong market demand and lower material costs. Partially offsetting these increases were lower ready-mixed concrete volumes and margins due to a decrease in available work and unfavorable weather conditions in certain regions.

Selling, general and administrative expense: Increase of $5.4 million, primarily payroll-related costs, acquisition costs and higher insurance-related costs.

Other income (expense): Decrease of $3.5 million, largely the result of lower returns on investments.

Interest expense: Increase of $2.5 million, largely resulting from higher debt balances as a result of recent acquisitions, capital expenditures and higher working capital needs.

Income taxes: Increase of $23.0 million, primarily resulting from the absence in 2018 of a $41.9 million tax benefit recorded in the fourth quarter of 2017 for the revaluation of the segment's net deferred tax liabilities. Partially offsetting this increase were lower income taxes due to the enactment of the TCJA, which reduced the corporate tax rate.

Outlook The segment's vertically integrated aggregate-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 state and 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 IBISWorld Incorporated Industry Report issued in June 2019 for sand and gravel mining in the United States projects a 1.1 percent annual growth rate through 2024. The report also states the demand for clay and refractory materials is projected to continue deteriorating in several downstream manufacturing industries. However, the report expects this decline will be offset by rising activity in the residential and nonresidential construction markets, growing public sector investment in the highway and bridge construction markets and the oil and gas sector growth. The Company believes stronger demand in the housing construction 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.

During 2019 and 2018, the Company made strategic asset purchases and acquired businesses that support the Company's long-term strategy to expand its market presence. In the first quarter of 2019, the Company purchased additional aggregate deposits in Texas, which augments the segment's existing operations and enhances its ability to sell aggregates to third parties in the coming years. Also, in the first quarter of 2019, the Company acquired Viesko Redi-Mix, Inc., a ready mixed concrete supplier headquartered near Salem, Oregon. In the fourth quarter of 2019, the Company acquired Roadrunner Ready Mix, Inc., a ready-mixed concrete supplier in Idaho. In the first quarter of 2020, the Company acquired the assets of Oldcastle Infrastructure Spokane, a prestressed-concrete business located in Spokane, Washington. The Company continues to evaluate additional acquisition opportunities. For more information on the Company's business combinations, see Item 8 - Note 3.

The construction materials and contracting segment had backlog at December 31, 2019, of $693 million, which was comparable to backlog at December 31, 2018, of $706 million. The Company expects to complete a significant amount of backlog at December 31, 2019, during the next 12 months.

During the second quarter of 2019, the governor of Oregon signed House Bill 3427, which creates a Corporate Activity Tax. The tax was enacted in the third quarter of 2019 and was effective for the Company on January 1, 2020. The Company expects the additional taxation will be less than $2.0 million annually at the construction materials and contracting segment, which is dependent on the level of taxable commercial activity in Oregon.

Construction Services

Strategy and challenges The construction services segment provides inside and outside specialty contracting, as discussed in Items 1 and 2 - Business Properties. The construction services segment focuses on safely executing projects; providing a superior return on investment by building new and strengthening existing customer relationships; ensuring quality service; 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 growth experienced by the segment in recent years is due in part to its ability to support national customers in most of the regions in which they operate.

The construction services segment faces challenges in the highly competitive markets in which it operates. Competitive pricing environments, project delays, changes in management's estimates of variable consideration and the effects from restrictive regulatory requirements have negatively impacted revenues and margins in the past and could affect revenues and 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, the Company believes overall customer and competitor demand for labor resources will continue to increase, possibly surpassing the supply of industry resources.

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

Years ended December 31,	**2019**	2018	2017
		(In millions)	
Operating revenues	**$ 1,849.3**	$ 1,371.5	$ 1,367.6
Cost of sales:			
Operation and maintenance	**1,555.4**	1,150.4	1,153.9
Depreciation, depletion and amortization	**15.0**	14.3	14.2
Taxes, other than income	**58.8**	42.0	43.4
Total cost of sales	**1,629.2**	1,206.7	1,211.5
Gross margin	**220.1**	164.8	156.1
Selling, general and administrative expense:			
Operation and maintenance	**87.0**	72.2	69.3
Depreciation, depletion and amortization	**2.0**	1.4	1.5
Taxes, other than income	**4.7**	4.4	4.0
Total selling, general and administrative expense	**93.7**	78.0	74.8
Operating income	**126.4**	86.8	81.3
Other income	**1.9**	1.1	1.3
Interest expense	**5.3**	3.6	3.7
Income before income taxes	**123.0**	84.3	78.9
Income taxes	**30.0**	20.0	25.6
Net income	**$ 93.0**	$ 64.3	$ 53.3

2019 compared to 2018 Construction services earnings increased $28.7 million (45 percent) as a result of:

Revenues: Increase of $477.8 million, largely resulting from higher inside specialty contracting workloads from an increase in customer demand for hospitality, data center and high-tech projects. Also contributing to the increase was higher outside specialty contracting workloads, primarily resulting from increased utility customer demand.

Gross margin: Increase of $55.3 million, primarily due to the higher volume of work resulting in an increase in revenues, as previously discussed, partially offset by an increase in operation and maintenance expense as a direct result of the increased workloads.

Selling, general and administrative expense: Increase of $15.7 million, resulting from increased payroll-related costs, as well as higher office expense and outside professional service costs.

Other income: Increase of $800,000, largely resulting from higher returns on the Company's benefit plan investments.

Interest expense: Increase of $1.7 million, related to higher debt balances as a result of additional working capital needs from the increase in contracting workloads in 2019.

Income taxes: Increase of $10.0 million, directly resulting from an increase in income before taxes.

2018 compared to 2017 Construction services earnings increased $11.0 million (21 percent) as a result of:

Revenues: Comparable to the prior year.

Gross margin: Increase of $8.7 million, largely resulting from higher outside specialty contracting gross margins due to increased outside equipment sales and rentals. Partially offsetting the increase were decreased inside specialty contracting gross margins as a result of decreased workloads and customer demand.

Selling, general and administrative expense: Increase of $3.2 million, primarily higher office expense, outside professional costs and payroll-related costs.

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $5.6 million, largely the lower corporate tax rate due to the enactment of the TCJA.

Outlook The Company expects bidding activity to remain strong for both inside and outside specialty construction companies in 2020. Although bidding remains highly competitive in all areas, the Company expects the segment's skilled workforce, quality of service and effective cost management will continue to provide a benefit in securing and executing profitable projects.

The construction services segment had backlog at December 31, 2019, of $1.1 billion, up from $939 million at December 31, 2018. The 22 percent increase in backlog was largely attributable to the new project opportunities that the Company continues to be awarded across its diverse operations, particularly inside specialty electrical and mechanical contracting in the hospitality, high-tech, mission critical and public industries. The Company's outside power, communications and natural gas specialty contracting also have a high volume of available work. The Company expects to complete a significant amount of backlog at December 31, 2019, during the next 12 months. Additionally, the Company continues to further evaluate potential acquisition opportunities that would be accretive to the Company and continue to grow the Company's backlog.

In support of the Company's strategic plan to grow through acquisitions, the Company purchased the assets of Pride Electric, Inc., an electrical construction company in Redmond, Washington, in the third quarter of 2019. In the first quarter of 2020, the Company acquired PerLectric, Inc., an electrical construction company in Fairfax, Virginia. For more information on the Company's business combinations, see Item 8 - Note 3.

During the second quarter of 2019, the governor of Oregon signed House Bill 3427, which creates a Corporate Activity Tax. The tax was enacted in the third quarter of 2019 and was effective for the Company on January 1, 2020. The Company expects the additional taxation will be less than $2.0 million annually at the construction services segment, which is dependent on the level of taxable commercial activity in Oregon.

Other

Years ended December 31,	**2019**	2018	2017
		(In millions)	
Operating revenues	**$ 16.6**	$ 11.3	$ 7.9
Operating expenses:			
Operation and maintenance	**15.6**	9.3	6.3
Depreciation, depletion and amortization	**2.1**	2.0	2.0
Taxes, other than income	**.1**	.1	.2
Total operating expenses	**17.8**	11.4	8.5
Operating loss	**(1.2)**	(.1)	(.6)
Other income	**.9**	1.0	.9
Interest expense	**1.9**	2.8	3.6
Loss before income taxes	**(2.2)**	(1.9)	(3.3)
Income taxes	**(.1)**	(1.2)	(1.8)
Net loss	**$ (2.1)**	$ (.7)	$ (1.5)

Included in Other is insurance activity at the Company's captive insurer which impacts both operating revenues and operation and maintenance expense. 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 are also included in Other. Additionally, operation and maintenance expense in 2018 included costs associated with the Holding Company Reorganization. For further details on the Company's reorganization, see Items 1 and 2 Business Properties - General.

Discontinued Operations

Years ended December 31,	**2019**	2018	2017
	(In millions)		
Income from discontinued operations before intercompany eliminations, net of tax	**$ .3**	$ 2.9	$ 3.1
Intercompany eliminations	**—**	—	(6.9)
Income (loss) from discontinued operations, net of tax	**$ .3**	$ 2.9	$ (3.8)

Included in discontinued operations are the results and supporting activities of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense. The loss in 2017 was largely attributable to eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

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,	**2019**	2018	2017
	(In millions)		
Intersegment transactions:			
Operating revenues	**$ 77.1**	$ 64.3	$ 58.0
Operation and maintenance	**21.1**	13.7	9.1
Purchased natural gas sold	**56.0**	50.6	48.9
Income from continuing operations*	**—**	—	(6.9)

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

For more information on intersegment eliminations, see Item 8 - Note 16.

Liquidity and Capital Commitments

At December 31, 2019, the Company had cash and cash equivalents of $66.5 million and available borrowing capacity of $644.4 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 are also affected by changes in working capital. Changes in cash flows for discontinued operations are related to the Company's former exploration and production and refining businesses.

Cash flows provided by operating activities in 2019 increased $42.4 million from 2018. The increase in cash flows provided by operating activities in 2019 was largely driven by increased earnings from higher workloads at the construction businesses, which were partially offset by an increase in accounts receivable as a result of the higher workloads. Lower inventory balances due to higher workloads at the construction materials and contracting business in 2019 as compared to the increase in inventory balances in 2018 due to the activity of acquired businesses also contributed to the increase. Partially offsetting these increases were higher natural gas purchases including the effects of colder weather, higher gas costs and the timing of collection of such balances from customers at the natural gas distribution business, as well as higher pension contributions at all of the businesses.

Cash flows provided by operating activities in 2018 increased $51.9 million from 2017. The increase in cash flows provided by operating activities was largely driven by stronger collection of accounts receivable at the construction services and construction materials and contracting businesses and bonus depreciation for tax purposes due to the enactment of TCJA at the construction materials and contracting business. Partially offsetting these increases were higher inventory balances at the construction materials and contracting business due to higher asphalt oil inventory, largely resulting from higher average per ton cost, and higher aggregate inventory from higher production. Also contributing to the decrease were decreased deferral of production tax credits, re-measurements of taxes on investments and accelerated tax deductions related to TCJA.

Investing activities Cash flows used in investing activities in 2019 decreased $107.0 million from 2018. The decrease in cash used was primarily related to $112.1 million lower cash used in acquisition activity in 2019 compared to 2018 at the construction materials and contracting business and higher proceeds on asset sales at the construction businesses in 2019.

Cash flows used in investing activities in 2018 increased $496.7 million from 2017. The increase in cash used in investing activities was primarily related to acquisition activity in 2018 at the construction materials and contracting business; the absence in 2018 of net proceeds from the sale of Pronghorn in January 2017 and higher capital expenditures in 2018 at the pipeline and midstream business; and higher capital expenditures related to various construction projects in 2018 at the electric and natural gas distribution businesses.

Financing activities Cash flows provided by financing activities in 2019 decreased $156.3 million from 2018. The decrease in cash provided by financing activities was largely due to the higher repayment of long-term debt in 2019 on debt issued in 2018 for acquisitions at the construction materials and contracting business. The Company also borrowed and repaid short-term borrowings in 2019. Partially offsetting the decrease in cash provided by financing activities was the receipt of proceeds from the issuance of common stock. The Company issued common stock for net proceeds of $106.8 million under its "at-the-market" offering and 401(k) plan in 2019.

Cash flows provided by financing activities in 2018 increased $475.7 million from 2017. The increase in cash provided by financing activities was largely due to increased debt issuance from an increase in commercial paper balances used for acquisitions, ongoing capital expenditures and working capital needs at the construction materials and contacting business; the issuance of an additional $200 million in term loans for capital projects at the electric and natural gas distribution businesses; and the issuance of an additional $40 million under the private shelf agreement for capital projects at the pipeline and midstream business. The increase in issuance of long-term debt was partially offset by higher debt repayment on a line of credit at the natural gas distribution business; higher debt repayment on debt that matured during third quarter 2018 at the electric and natural gas distribution businesses; and the strong collection of accounts receivable resulting in lower commercial paper balances at the construction services business.

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 and expected return on plan assets. At December 31, 2019, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $55.9 million. Pretax pension expense reflected in the Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017, was $2.5 million, $843,000 and $1.7 million, respectively. The Company's pension expense is currently projected to be approximately $300,000 in 2020. Funding for the pension plans is actuarially determined. The minimum required contributions for the years ended December 31, 2019 and 2018, were approximately $4.9 million and $6.1 million, respectively. There were no minimum required contributions for the year ended December 31, 2017. For more information on the Company's pension plans, see Item 8 - Note 17.

Capital expenditures

The Company's capital expenditures from continuing operations for 2017 through 2019 and as anticipated for 2020 through 2022 are summarized in the following table.

	Actual*			Estimated		
	2017	2018	**2019**	2020	2021	2022
			(In millions)			
Capital expenditures:						
Electric	$ 109	$ 186	**$ 99**	$ 111	$ 128	$ 139
Natural gas distribution	147	206	**207**	221	191	180
Pipeline and midstream	31	70	**71**	85	304	53
Construction materials and contracting	44	280	**190**	167	154	157
Construction services	19	25	**61**	61	20	20
Other	2	2	**8**	5	3	3
Total capital expenditures	$ 352	$ 769	**$ 636**	$ 650	$ 800	$ 552

* Capital expenditures for 2019, 2018 and 2017 include noncash transactions such as the issuance of the Company's equity securities in connection with acquisitions, capital expenditure-related accounts payable and AFUDC, totaling $4.8 million, $33.4 million and $10.5 million, respectively.

The 2019 capital expenditures include the two business combinations at the construction materials and contracting segment and one business combination at the construction services segment, as discussed in Item 8 - Note 3. The 2019 capital expenditures were funded by internal sources, issuance of long-term debt and issuance of the Company's equity securities. The Company has included in the estimated capital expenditures for 2020 through 2022 the Demicks Lake Expansion project, North Bakken Expansion project, construction of Heskett Unit 4 and the recently completed business combination at the construction services segment, as previously discussed in Business Segment Financial and Operating Data.

Estimated capital expenditures for the years 2020 through 2022 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and natural gas storage projects
- Power generation and transmission opportunities
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities that would be incremental to the outlined capital program; 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 2020 through 2022 will be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; and issuance of debt and equity securities.

Capital resources

Certain debt instruments of the Company's subsidiaries, including those discussed later, contain restrictive and financial covenants and cross-default provisions. In order to borrow under the debt agreements, the subsidiary companies must be in compliance with the applicable covenants and certain other conditions, all of which the subsidiaries, as applicable, were in compliance with at December 31, 2019. In the event the subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 9.

The following table summarizes the outstanding revolving credit facilities of the Company's subsidiaries at December 31, 2019:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
					(In millions)				
Montana-Dakota Utilities Co.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 118.6	(b)	$ —		12/19/24
Cascade Natural Gas Corporation	Revolving credit agreement		$ 100.0	(c)	$ 64.6		$ 2.2	(d)	6/7/24
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 24.5		$ 1.4	(d)	6/7/24
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 600.0		$ 104.3	(b)	$ —		12/19/24

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Montana-Dakota 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 $125.0 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 $700.0 million). There were no amounts outstanding under the revolving credit agreement.

The 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, Montana-Dakota 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 certain operations of the Company's subsidiaries.

Total equity as a percent of total capitalization was 56 percent and 55 percent at December 31, 2019 and 2018, 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 Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities. The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

On February 22, 2019, the Company entered into a Distribution Agreement with J.P. Morgan Securities LLC and MUFG Securities Americas Inc., as sales agents, with respect to the issuance and sale of up to 10.0 million shares of the Company's common stock in connection with an “at-the-market” offering. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Proceeds from the sale of shares of common stock under the agreement have been and are expected to be used for general corporate purposes, which may include, among other things, working capital, capital expenditures, debt repayment and the financing of acquisitions.

The Company issued 3.6 million shares of common stock for the year ended December 31, 2019, pursuant to the “at-the-market” offering. For the year ended December 31, 2019, the Company received net proceeds of $94.0 million and paid commissions to the sales agents of approximately $950,000 in connection with the sales of common stock under the "at-the-market" offering. The net proceeds were used for capital expenditures and acquisitions. As of December 31, 2019, the Company had remaining capacity to issue up to 6.4 million additional shares of common stock under the "at-the-market" offering program.

Certain of the Company's debt instruments use LIBOR as a benchmark for establishing the applicable interest rate. LIBOR is the subject of recent national, international and other regulatory guidance and proposals for reform. These reforms and other pressures may cause LIBOR to disappear entirely or to perform differently than in the past. The Company has been proactive to anticipate the reform of LIBOR by replacing it with Secured Overnight Financing Rate in certain of its new debt instruments, as well as those that are being renewed. The Company continues to evaluate the impact the reform will have on its debt instruments and, at this time, does not anticipate a significant impact.

The following includes information related to the preceding table.

Montana-Dakota On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same.

On December 19, 2019, Montana-Dakota amended and restated its revolving credit agreement extending the maturity date to December 19, 2024. Montana-Dakota'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. Montana-Dakota's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Historically, downgrades in credit ratings have not limited, nor are currently expected to limit, Montana-Dakota's ability to access the capital markets. If Montana-Dakota 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, Montana-Dakota expects that it will negotiate the extension or replacement of this agreement. If Montana-Dakota 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 Montana-Dakota does not currently anticipate, it would seek alternative funding.

On July 24, 2019, Montana-Dakota entered into a $200.0 million note purchase agreement with maturity dates ranging from October 17, 2039 to November 18, 2059, at a weighted average interest rate of 3.95 percent.

Cascade On June 7, 2019, Cascade amended its revolving credit agreement to increase the borrowing limit to $100.0 million and extend the maturity date to June 7, 2024. 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 June 13, 2019, Cascade issued $75.0 million of senior notes under a note purchase agreement with maturity dates ranging from June 13, 2029 to June 13, 2049, at a weighted average interest rate of 3.93 percent.

Intermountain On June 7, 2019, Intermountain amended its revolving credit agreement to extend the maturity date to June 7, 2024. 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 June 13, 2019, Intermountain issued $50.0 million of senior notes under a note purchase agreement with maturity dates ranging from June 13, 2029 to June 13, 2049, at a weighted average interest rate of 3.92 percent.

Centennial On December 19, 2019, Centennial amended and restated its revolving credit agreement to increase the borrowing capacity to $600.0 million and extend the maturity date to December 19, 2024. 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.

On April 4, 2019, Centennial issued $150.0 million of senior notes under a note purchase agreement with maturity dates ranging from April 4, 2029 to April 4, 2034, at a weighted average interest rate of 4.60 percent.

WBI Energy Transmission On July 26, 2019, WBI Energy Transmission amended its uncommitted note purchase and private shelf agreement to increase capacity to $300.0 million and extend the issuance period and expiration date to May 16, 2022. On December 16, 2019, WBI Energy Transmission issued $45.0 million of senior notes under the private shelf agreement with a maturity date of December 16, 2034, at an interest rate of 4.17 percent. WBI Energy Transmission had $170.0 million of notes outstanding at December 31, 2019, which reduced the remaining capacity under this uncommitted private shelf agreement to $130.0 million.

Dividend restrictions

For information on the Company's dividends and dividend restrictions, see Item 8 - Note 12.

Off balance sheet arrangements

As of December 31, 2019, 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 9 and 20. At December 31, 2019, the Company's commitments under these obligations were as follows:

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
			(In millions)		
Long-term debt maturities*	$ 16.6	$ 149.5	$ 451.3	$ 1,632.8	$ 2,250.2
Estimated interest payments**	.8	6.6	13.9	74.4	95.7
Operating leases	35.2	41.8	17.6	47.9	142.5
Purchase commitments	405.5	434.5	210.5	678.4	1,728.9
	$ 458.1	$ 632.4	$ 693.3	$ 2,433.5	$ 4,217.3

* Unamortized debt issuance costs and discount are excluded from the table.
** Represents the estimated interest payments associated with the Company's long-term debt outstanding at December 31, 2019, assuming current interest rates and consistent amounts outstanding until their respective maturity dates over the periods indicated in the table above.

At December 31, 2019, the Company had total liabilities of $417.6 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, 2019, 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 10.

Not reflected in the previous table are $576,000 in uncertain tax positions at December 31, 2019.

The Company has no minimum funding requirements for its defined benefit pension plans for 2020 due to the additional contribution of $20.0 million in 2019.

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 17.

New Accounting Standards

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

Critical Accounting Policies Involving Significant Estimates

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

Estimates are used for items such as impairment testing of long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; revenue recognized using the cost-to-cost measure of progress for contracts; uncollectible accounts; environmental and other loss contingencies; regulatory assets expected to be recovered in rates charged to customers; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; lease classification; present value of right-of-use assets and lease liabilities; 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.

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

The 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 16. Goodwill impairment, if any, is measured by 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 goodwill of the reporting unit is not impaired. If the carrying value of a reporting unit exceeds its fair value, the Company must record an impairment loss for the amount that the carrying value of the reporting unit, including goodwill, exceeds the fair value of the reporting unit. For the years ended December 31, 2019, 2018 and 2017, there were no impairment losses recorded. At December 31, 2019, 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, risk adjusted capital cost, 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 risk adjusted capital cost at each reporting unit. Risk adjusted capital cost, which varies by reporting unit and was in the range of 4 percent to 9 percent, was utilized in the goodwill impairment test performed in the fourth quarter of 2019. The goodwill impairment test also utilizes a long-term growth rate projection, which varies by reporting unit and was in the range of approximately 2 percent to 3 percent in the goodwill impairment test performed in the fourth quarter of 2019. Under the market approach, the Company estimates fair value using various multiples derived from 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.

Business combinations

The Company accounts for acquisitions on the Consolidated Financial Statements starting from the date of the acquisition, which is the date that control is obtained. The acquisition method of accounting requires acquired assets and liabilities assumed be recorded at their respective fair values as of the date of the acquisition. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The estimation of fair values of acquired assets and liabilities assumed by the Company requires significant judgment and requires various assumptions. Although independent appraisals may be used to assist in the determination of the fair value of certain assets and liabilities, the appraised values may be based on significant estimates provided by management. The amounts and useful lives assigned to depreciable and amortizable assets compared to amounts assigned to goodwill, which is not amortized, can affect the results of operations in the period of and periods subsequent to a business combination.

In determining fair values of acquired assets and liabilities assumed, the Company uses various observable inputs for similar assets or liabilities in active markets and various unobservable inputs, which includes the use of valuation models. Fair values are based on various factors including, but not limited to, age and condition of property, maintenance records, auction values for equipment with similar characteristics, recent sales and listings of comparable properties, data collected from drill holes and other subsurface investigations and geologic data. The Company primarily uses the market and cost approaches in determining the fair value of land and property, plant and equipment. A combination of the market and income approaches are used for aggregate reserves and intangibles, primarily a discounted cash flow model.

There is a measurement period after the acquisition date during which the Company may adjust the amounts recognized for a business combination. Any such adjustments are recorded in the period the adjustment is determined with the corresponding offset to goodwill. These adjustments are typically based on obtaining additional information that existed at the acquisition date regarding the assets acquired and the liabilities assumed. The measurement period ends once the Company has obtained all necessary information that existed as of the acquisition date, but does not extend beyond one year from the date of the acquisition. Once the measurement period has ended, any adjustments to assets acquired or liabilities assumed are recorded in income from continuing operations.

Regulatory accounting

The Company is subject to rate regulation by state public service commissions and/or the FERC. The Company's regulated businesses 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. Regulatory assets generally represent incurred or accrued costs that have been deferred and are expected to be recovered in rates charged to customers. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. Management continually assesses the likelihood of recovery in future rates of incurred costs and refunds to customers associated with regulatory assets and liabilities. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. The Company believes that the accounting subject to rate regulation remains appropriate and its regulatory assets are probable of recovery in current rates or in future rate proceedings.

Revenue recognition

Revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. The accuracy of revenues reported on the Consolidated Financial Statements depends on, among other things, management's estimates of total costs to complete projects because the Company uses the cost-to-cost measure of progress on construction contracts for revenue recognition.

To determine the proper revenue recognition method for contracts, the Company evaluates whether two or more contracts should be combined and accounted for as one single contract and whether the combined or single contract should be accounted for as more than one performance obligation. This evaluation requires significant judgment and the decision to combine a group of contracts or separate the combined or single contract into multiple performance obligations could change the amount of revenue and profit recorded in a given period. For most contracts, the customer contracts with the Company to provide a significant service of integrating a complex set of tasks and components into a single project. Hence, the Company's contracts are generally accounted for as one performance obligation.

The Company recognizes construction contract revenue over time using an input method based on the cost-to-cost measure of progress for contracts because it best depicts the transfer of assets to the customer which occurs as the Company incurs costs on the contract. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. 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. For the years ended December 31, 2019 and 2018, the Company's total construction contract revenue was $2.8 billion and $2.2 billion, respectively.

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.

Contracts are often modified to account for changes in contract specifications and requirements. The Company considers contract modifications to exist when the modification either creates new or changes the existing enforceable rights and obligations. Generally, contract modifications are for goods or services that are not distinct from the existing contract due to the significant integration of services provided in the context of the contract and are accounted for as if they were part of that existing contract. The effect of a contract modification on the transaction price and the measure of progress for the performance obligation to which it relates, is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company's construction contracts generally contain variable consideration including liquidated damages, performance bonuses or incentives, claims, unapproved/unpriced change orders and penalties or index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company believes its estimates surrounding the cost-to-cost method 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.

Pension and other postretirement benefits

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

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases, actuarially determined mortality data and health care cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions, the mix of investments 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 approximately $1.7 million (after-tax) for the year ended December 31, 2019.

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 17.

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, franchise and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements 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.

Non-GAAP Financial Measures

The Business Segment Financial and Operating Data includes financial information prepared in accordance with GAAP, as well as another financial measure, adjusted gross margin, that is considered a non-GAAP financial measure as it relates to the Company's electric and natural gas distribution segments. The presentation of adjusted gross margin is intended to be a useful supplemental financial measure for investors' understanding of the segments' operating performance. This non-GAAP financial measure should not be considered as an alternative to, or more meaningful than, GAAP financial measures such as operating income (loss) or net income (loss). The Company's non-GAAP financial measure, adjusted gross margin, is not standardized; therefore, it may not be possible to compare this financial measure with other companies' gross margin measures having the same or similar names.

In addition to operating revenues and operating expenses, management also uses the non-GAAP financial measure of adjusted gross margin when evaluating the results of operations for the electric and natural gas distribution segments. Adjusted gross margin for the electric and natural gas distribution segments is calculated by adding back adjustments to operating income (loss). These add-back adjustments include: operation and maintenance expense; depreciation, depletion and amortization expense; and certain taxes, other than income.

Adjusted gross margin includes operating revenues less the cost of electric fuel and purchased power, purchased natural gas sold and certain taxes, other than income. These taxes, other than income, included as a reduction to adjusted gross margin relate to revenue taxes. These segments pass on to their customers the increases and decreases in the wholesale cost of power purchases, natural gas and other fuel supply costs in accordance with regulatory requirements. As such, the segments' revenues are directly impacted by the fluctuations in such commodities. Revenue taxes, which are passed back to customers, fluctuate with revenues as they are calculated as a percentage of revenues. For these reasons, period over period, the segments' operating income (loss) is generally not impacted. The Company's management believes the adjusted gross margin is a useful supplemental financial measure as these items are included in both operating revenues and operating expenses. The Company's management also believes that adjusted gross margin and the remaining operating expenses that calculate operating income (loss) are useful in assessing the Company's utility performance as management has the ability to influence control over the remaining operating expenses.

The following information reconciles operating income to adjusted gross margin for the electric segment.

Years ended December 31,	**2019**	2018	2017
		(In millions)	
Operating income	**$ 64.0**	$ 65.2	$ 79.9
Adjustments:			
Operating expenses:			
Operation and maintenance	**125.7**	123.0	122.2
Depreciation, depletion and amortization	**58.7**	51.0	47.7
Taxes, other than income	**16.1**	14.5	13.5
Total adjustments	**200.5**	188.5	183.4
Adjusted gross margin	**$ 264.5**	$ 253.7	$ 263.3

The following information reconciles operating income to adjusted gross margin for the natural gas distribution segment.

Years ended December 31,	**2019**	2018	2017
		(In millions)	
Operating income	**$ 69.2**	$ 72.3	$ 84.3
Adjustments:			
Operating expenses:			
Operation and maintenance	**185.0**	173.4	164.3
Depreciation, depletion and amortization	**79.6**	72.5	69.4
Taxes, other than income	**23.5**	21.7	20.5
Total adjustments	**288.1**	267.6	254.2
Adjusted gross margin	**$ 357.3**	$ 339.9	$ 338.5

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2019, 2018 or 2017.

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 8 and 9.

At December 31, 2019 and 2018, 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, 2019.

	2020	2021	2022	2023	2024	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 16.6	$ 1.5	$ 148.0	$ 77.9	$ 61.4	$ 1,632.8	$ 1,938.2	$ 2,113.7
Weighted average interest rate	4.8%	1.1%	4.5%	3.7%	4.2%	4.6%	4.5%	
Variable rate	$ —	$ —	$ —	$ —	$ 312.0	$ —	$ 312.0	$ 312.0
Weighted average interest rate	—%	—%	—%	—%	2.7%	—%	2.7%	

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, 2019. 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, 2019.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2019, 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, 2019 and 2018, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 21, 2020, 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 included 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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Revenue from Contracts with Customers-Construction Contract Revenue-Refer to Notes 1 and 2 to the financial statements

Critical Audit Matter Description

The Company recognizes construction contract revenue over time using an input method based on the cost-to-cost measure of progress as it best depicts the transfer of assets to the customer. Under this method of measuring progress, costs incurred are compared with total estimated costs of the performance obligation and revenues are recorded proportionately to the costs incurred. Ordinarily the Company's contracts represent a single distinct performance obligation due to the highly interdependent and interrelated nature of the underlying goods or services. For the year ended December 31, 2019, the Company recognized $2.8 billion of construction contract revenue.

Given the judgments necessary to estimate total costs and profit for the performance obligations used to recognize revenue for construction contracts, auditing such estimates required extensive audit effort due to the volume and complexity of construction contracts and a high degree of auditor judgment when performing audit procedures and evaluating the results of those procedures.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's estimates of total costs and profit for the performance obligations used to recognize revenue for certain construction contracts included the following, among others:

- We evaluated the operating effectiveness of controls over construction contract revenue, including those over management's estimation of total costs and profit for the performance obligations.
- We developed an expectation of the amount of construction contract revenues based on prior year margins, and taking into account current year events, applied to the construction contract costs in the current year and compared our expectation to the amount of construction contract revenues recorded by management.
- We selected a sample of construction contracts and performed the following:
  - Evaluated whether the contracts were properly included in management's calculation of construction contract revenue based on the terms and conditions of each contract, including whether continuous transfer of control to the customer occurred as progress was made toward fulfilling the performance obligation.
  - Compared the transaction prices to the consideration expected to be received based on current rights and obligations under the contracts and any modifications that were agreed upon with the customers.
  - Evaluated management's identification of distinct performance obligations by evaluating whether the underlying goods, services, or both were highly interdependent and interrelated.
  - Tested the accuracy and completeness of the costs incurred to date for the performance obligation.
  - Evaluated the estimates of total cost and profit for the performance obligation by:
    - Observing the work sites and inspecting the progress to completion.
    - Comparing costs incurred to date to the costs management estimated to be incurred to date.
    - Evaluating management's ability to achieve the estimates of total cost and profit by performing corroborating inquiries with the Company's project managers and engineers, and comparing the estimates to management's work plans, engineering specifications, and supplier contracts.
    - Comparing management's estimates for the selected contracts to costs and profits of similar performance obligations, when applicable.
- Tested the mathematical accuracy of management's calculation of construction contract revenue for the performance obligation.
- We evaluated management's ability to estimate total costs and profits accurately by comparing actual costs and profits to management's historical estimates for performance obligations that have been fulfilled.

Regulatory Matters-Impact of Rate Regulation on the Financial Statements-Refer to Notes 1 and 19 to the financial statements

Critical Audit Matter Description

Through the Company's regulated utility businesses, it provides electric and natural gas services to customers, and generates, transmits, and distributes electricity. The Company is subject to rate regulation by federal and state utility regulatory agencies (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas distribution companies in states where the Company operates. The Company's regulated utility 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.

Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on the Company's investment in the regulated utility businesses. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. The regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations.

Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; and depreciation expense. We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) refunds to customers. Given management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments requires specialized knowledge of accounting for rate regulation due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the design and operating effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets; and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We tested management's controls over the initial recognition of amounts as regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company and other public utilities in the Company's significant jurisdictions, regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of the treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, for any evidence that might contradict management's assertions.
- We obtained an analysis from management regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery, or that a future reduction in rates is not likely.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 21, 2020

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

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, 2019, 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, 2019, 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, 2019, of the Company and our report dated February 21, 2020, 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.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 21, 2020

Consolidated Statements of Income

Years ended December 31,	2019	2018	2017
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	**$ 1,279,304**	$ 1,213,227	$ 1,244,759
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**4,057,472**	3,318,325	3,198,592
Total operating revenues	**5,336,776**	4,531,552	4,443,351
Operating expenses:			
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	**356,132**	340,331	326,687
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**3,539,162**	2,915,790	2,808,779
Total operation and maintenance	**3,895,294**	3,256,121	3,135,466
Purchased natural gas sold	**421,545**	404,153	430,954
Depreciation, depletion and amortization	**256,017**	220,205	207,486
Taxes, other than income	**196,143**	168,638	166,673
Electric fuel and purchased power	**86,557**	80,712	78,724
Total operating expenses	**4,855,556**	4,129,829	4,019,303
Operating income	**481,220**	401,723	424,048
Other income (expense)	**15,812**	(238)	8,767
Interest expense	**98,587**	84,614	82,788
Income before income taxes	**398,445**	316,871	350,027
Income taxes	**63,279**	47,485	65,041
Income from continuing operations	**335,166**	269,386	284,986
Income (loss) from discontinued operations, net of tax	**287**	2,932	(3,783)
Net income	**335,453**	272,318	281,203
Loss on redemption of preferred stock	**—**	—	600
Dividends declared on preferred stock	**—**	—	171
Earnings on common stock	**$ 335,453**	$ 272,318	$ 280,432
Earnings per common share - basic:			
Earnings before discontinued operations	**$ 1.69**	$ 1.38	$ 1.46
Discontinued operations, net of tax	**—**	.01	(.02)
Earnings per common share - basic	**$ 1.69**	$ 1.39	$ 1.44
Earnings per common share - diluted:			
Earnings before discontinued operations	**$ 1.69**	$ 1.38	$ 1.45
Discontinued operations, net of tax	**—**	.01	(.02)
Earnings per common share - diluted	**$ 1.69**	$ 1.39	$ 1.43
Weighted average common shares outstanding - basic	**198,612**	195,720	195,304
Weighted average common shares outstanding - diluted	**198,626**	196,150	195,687

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2019	2018	2017
		(In thousands)	
Net income	**$ 335,453**	$ 272,318	$ 281,203
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income, net of tax of $(140), $429 and $224 in 2019, 2018 and 2017, respectively	**731**	162	366
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $(2,012), $1,471 and $(1,162) in 2019, 2018 and 2017, respectively	**(6,151)**	4,441	(1,812)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $476, $721 and $645 in 2019, 2018 and 2017, respectively	**1,486**	2,173	1,013
Reclassification of postretirement liability adjustment from regulatory asset, net of tax of $0, $0 and $(876) in 2019, 2018 and 2017, respectively	**—**	—	(1,143)
Postretirement liability adjustment	**(4,665)**	6,614	(1,942)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $0, $(14) and $(3) in 2019, 2018 and 2017, respectively	**—**	(61)	(6)
Reclassification adjustment for foreign currency translation adjustment included in net income, net of tax of $0, $75 and $0 in 2019, 2018 and 2017, respectively	**—**	249	—
Foreign currency translation adjustment	**—**	188	(6)
Net unrealized gain (loss) on available-for-sale investments:			
Net unrealized gain (loss) on available-for-sale investments arising during the period, net of tax of $35, $(38) and $(75) in 2019, 2018 and 2017, respectively	**134**	(144)	(139)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $10, $35 and $65 in 2019, 2018 and 2017, respectively	**40**	131	120
Net unrealized gain (loss) on available-for-sale investments	**174**	(13)	(19)
Other comprehensive income (loss)	**(3,760)**	6,951	(1,601)
Comprehensive income attributable to common stockholders	**$ 331,693**	$ 279,269	$ 279,602

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

Consolidated Balance Sheets

December 31,	2019	2018
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 66,459**	$ 53,948
Receivables, net	**836,605**	722,945
Inventories	**278,407**	287,309
Prepayments and other current assets	**115,805**	119,500
Current assets held for sale	**425**	430
Total current assets	**1,297,701**	1,184,132
Investments	**148,656**	138,620
Property, plant and equipment	**7,908,628**	7,397,321
Less accumulated depreciation, depletion and amortization	**2,991,486**	2,818,644
Net property, plant and equipment	**4,917,142**	4,578,677
Deferred charges and other assets:		
Goodwill	**681,358**	664,922
Other intangible assets, net	**15,246**	10,815
Operating lease right-of-use assets	**115,323**	—
Other	**506,207**	408,857
Noncurrent assets held for sale	**1,426**	2,087
Total deferred charges and other assets	**1,319,560**	1,086,681
Total assets	**$ 7,683,059**	$ 6,988,110
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	**$ 16,540**	$ 251,854
Accounts payable	**403,391**	358,505
Taxes payable	**48,970**	41,929
Dividends payable	**41,580**	39,695
Accrued compensation	**99,269**	69,007
Current operating lease liabilities	**31,664**	—
Other accrued liabilities	**221,502**	221,059
Current liabilities held for sale	**3,511**	4,001
Total current liabilities	**866,427**	986,050
Long-term debt	**2,226,567**	1,856,841
Deferred credits and other liabilities:		
Deferred income taxes	**506,583**	430,085
Noncurrent operating lease liabilities	**83,742**	—
Other	**1,152,494**	1,148,359
Total deferred credits and other liabilities	**1,742,819**	1,578,444
Commitments and contingencies (Note 20)		
Stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value Shares issued - 200,922,790 at December 31, 2019 and 196,564,907 at December 31, 2018	**200,923**	196,565
Other paid-in capital	**1,355,404**	1,248,576
Retained earnings	**1,336,647**	1,163,602
Accumulated other comprehensive loss	**(42,102)**	(38,342)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total stockholders' equity	**2,847,246**	2,566,775
Total liabilities and stockholders' equity	**$ 7,683,059**	$ 6,988,110

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

Consolidated Statements of Equity

Years ended December 31, 2019, 2018 and 2017

	Preferred Stock		Common Stock				Accumulated Other Comprehensive Loss	Treasury Stock		
	Shares	Amount	Shares	Amount	Other Paid-in Capital	Retained Earnings		Shares	Amount	Total
					(In thousands, except shares)					
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 stock	—	—	—	—	—	(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)
At December 31, 2017	—	—	195,843,297	195,843	1,233,412	1,040,748	(37,334)	(538,921)	(3,626)	2,429,043
Cumulative effect of adoption of ASU 2014-09	—	—	—	—	—	(970)	—	—	—	(970)
Adjusted balance at January 1, 2018	—	—	195,843,297	195,843	1,233,412	1,039,778	(37,334)	(538,921)	(3,626)	2,428,073
Net income	—	—	—	—	—	272,318	—	—	—	272,318
Other comprehensive income	—	—	—	—	—	—	6,951	—	—	6,951
Reclassification of certain prior period tax effects from accumulated other comprehensive loss	—	—	—	—	—	7,959	(7,959)	—	—	—
Dividends declared on common stock	—	—	—	—	—	(156,453)	—	—	—	(156,453)
Stock-based compensation	—	—	—	—	5,060	—	—	—	—	5,060
Repurchase of common stock	—	—	—	—	—	—	—	(182,424)	(5,020)	(5,020)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	—	—	(7,350)	—	—	182,424	5,020	(2,330)
Issuance of common stock	—	—	721,610	722	17,454	—	—	—	—	18,176
At December 31, 2018	—	—	196,564,907	196,565	1,248,576	1,163,602	(38,342)	(538,921)	(3,626)	2,566,775
Net income	—	—	—	—	—	335,453	—	—	—	335,453
Other comprehensive loss	—	—	—	—	—	—	(3,760)	—	—	(3,760)
Dividends declared on common stock	—	—	—	—	—	(162,408)	—	—	—	(162,408)
Stock-based compensation	—	—	—	—	7,353	—	—	—	—	7,353
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	246,214	246	(3,261)	—	—	—	—	(3,015)
Issuance of common stock	—	—	4,111,669	4,112	102,736	—	—	—	—	106,848
At December 31, 2019	**—**	**$ —**	**200,922,790**	**$ 200,923**	**$ 1,355,404**	**$ 1,336,647**	**$ (42,102)**	**(538,921)**	**$ (3,626)**	**$ 2,847,246**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2019	2018	2017
		(In thousands)	
Operating activities:			
Net income	$ **335,453**	$ 272,318	$ 281,203
Income (loss) from discontinued operations, net of tax	**287**	2,932	(3,783)
Income from continuing operations	**335,166**	269,386	284,986
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**256,017**	220,205	207,486
Deferred income taxes	**63,415**	59,735	(25,423)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(104,374)**	28,234	(108,255)
Inventories	**9,331**	(46,796)	9,135
Other current assets	**(38,283)**	(31,814)	(30,588)
Accounts payable	**30,079**	21,109	26,013
Other current liabilities	**51,278**	22,285	4,648
Other noncurrent changes	**(60,813)**	(38,521)	(18,790)
Net cash provided by continuing operations	**541,816**	503,823	349,212
Net cash provided by (used in) discontinued operations	**464**	(3,942)	98,799
Net cash provided by operating activities	**542,280**	499,881	448,011
Investing activities:			
Capital expenditures	**(576,065)**	(568,230)	(341,382)
Acquisitions, net of cash acquired	**(55,597)**	(167,692)	—
Net proceeds from sale or disposition of property and other	**29,812**	26,100	126,588
Investments	**(2,011)**	(2,321)	(1,608)
Net cash used in continuing operations	**(603,861)**	(712,143)	(216,402)
Net cash provided by discontinued operations	**—**	1,236	2,234
Net cash used in investing activities	**(603,861)**	(710,907)	(214,168)
Financing activities:			
Issuance of short-term borrowings	**169,977**	—	—
Repayment of short-term borrowings	**(170,000)**	—	—
Issuance of long-term debt	**599,455**	566,829	140,812
Repayment of long-term debt	**(468,917)**	(174,520)	(217,394)
Proceeds from issuance of common stock	**106,848**	—	—
Payments of stock issuance costs	**—**	(10)	—
Dividends paid	**(160,256)**	(154,573)	(150,727)
Redemption of preferred stock	**—**	—	(15,600)
Repurchase of common stock	**—**	(5,020)	(1,684)
Tax withholding on stock-based compensation	**(3,015)**	(2,330)	(757)
Net cash provided by (used in) financing activities	**74,092**	230,376	(245,350)
Effect of exchange rate changes on cash and cash equivalents	**—**	(1)	(1)
Increase (decrease) in cash and cash equivalents	**12,511**	19,349	(11,508)
Cash and cash equivalents - beginning of year	**53,948**	34,599	46,107
Cash and cash equivalents - end of year	$ **66,459**	$ 53,948	$ 34,599

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 16. 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 7 for more information regarding the nature and amounts of these regulatory deferrals.

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota becoming a subsidiary of the Company. The purpose of the reorganization was to make the public utility division into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries.

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. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued rules that allowed 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. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Effective January 1, 2019, the Company adopted the requirements of the ASU on leases, as further discussed in this note, as well as in Note 5. As such, results for reporting periods beginning January 1, 2019, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with the historic accounting for leases.

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 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. 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 4.

Management has also evaluated the impact of events occurring after December 31, 2019, up to the date of issuance of these consolidated financial statements. For more information on the Company's subsequent events, see Note 21.

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 Note 2. The total balance of receivables past due 90 days or more was $46.7 million and $30.0 million at December 31, 2019 and 2018, 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, 2019 and 2018, was $8.5 million and $8.9 million, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at MDU Energy Capital was $100.8 million and $96.2 million at December 31, 2019 and 2018, respectively.

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

	2019	2018
	(In thousands)	
Short-term retainage*	**$ 75,590**	$ 56,228
Long-term retainage**	**14,228**	4,152
Total retainage	**$ 89,818**	$ 60,380

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

Inventories and natural gas in storage

Natural gas in storage for the Company's regulated operations is generally valued at lower of cost or market using the last-in, first-out method or lower of cost or net realizable value using the average cost or first-in, first-out method. The majority of all other inventories are valued at lower of cost or net realizable value using the average cost method. The portion of the cost of natural gas in storage expected to be used within 12 months was included in inventories. Inventories at December 31 consisted of:

	2019	2018
	(In thousands)	
Aggregates held for resale	**$ 147,723**	$ 139,681
Asphalt oil	**41,912**	54,741
Materials and supplies	**22,512**	23,611
Merchandise for resale	**22,232**	22,552
Natural gas in storage (current)	**22,058**	22,117
Other	**21,970**	24,607
Total	**$ 278,407**	$ 287,309

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 $48.4 million and $48.5 million at December 31, 2019 and 2018, 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 8 and 17.

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 for the years ended December 31 were as follows:

	2019	2018	2017
		(In thousands)	
AFUDC - borrowed	**$ 2,807**	$ 2,290	$ 966
AFUDC - equity	**$ 698**	$ 1,897	$ 909

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.

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

	2019	2018	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ **1,139,059**	$ 1,131,484	48
Distribution	**443,780**	430,750	46
Transmission	**445,485**	302,315	65
Construction in progress	**66,664**	161,893	—
Other	**132,157**	122,127	15
Natural gas distribution:			
Distribution	**2,133,249**	1,981,356	47
Construction in progress	**39,506**	21,028	—
Other	**515,368**	496,708	17
Pipeline and midstream:			
Transmission	**636,796**	585,594	46
Gathering	**35,661**	37,829	20
Storage	**50,001**	49,101	53
Construction in progress	**22,597**	5,915	—
Other	**48,340**	45,763	16
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	**31,148**	31,094	19
Construction in progress	**154**	86	—
Other	**9,518**	9,577	10
Construction materials and contracting:			
Land	**127,729**	109,541	—
Buildings and improvements	**122,064**	114,905	20
Machinery, vehicles and equipment	**1,180,343**	1,090,790	12
Construction in progress	**25,018**	22,507	—
Aggregate reserves	**455,408**	430,263	*
Construction services:			
Land	**7,146**	5,216	—
Buildings and improvements	**31,735**	29,795	24
Machinery, vehicles and equipment	**156,537**	145,859	6
Other	**17,952**	7,716	2
Other:			
Land	**2,648**	2,648	—
Other	**32,565**	25,461	14
Less accumulated depreciation, depletion and amortization	**2,991,486**	2,818,644	
Net property, plant and equipment	$ **4,917,142**	$ 4,578,677	

* 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. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income.

No significant impairment losses were recorded in 2019, 2018 or 2017. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Leases

Lease liabilities and their corresponding right-of-use assets are recorded based on the present value of lease payments over the expected lease term. The Company recognizes leases with an original lease term of 12 months or less in income on a straight-line basis over the term of the lease and does not recognize a corresponding right-of-use asset or lease liability. The Company determines the lease term based on the non-cancelable and cancelable periods in each contract. The non-cancelable period consists of the term of the contract that is legally enforceable and cannot be canceled by either party without incurring a significant penalty. The cancelable period is determined by various factors that are based on who has the right to cancel a contract. If only the lessor has the right to cancel the contract, the Company will assume the contract will continue. If the lessee is the only party that has the right to cancel the contract, the Company looks to asset, entity and market-based factors. If both the lessor and the lessee have the right to cancel the contract, the Company assumes the contract will not continue.

The discount rate used to calculate the present value of the lease liabilities is based upon the implied rate within each contract. If the rate is unknown or cannot be determined, the Company uses an incremental borrowing rate, which is determined by the length of the contract, asset class and the Company's borrowing rates, as of the commencement date of the contract.

Regulatory assets and liabilities

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. The Company records regulatory assets or liabilities at the time the Company determines the amounts to be recoverable in current or future rates.

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 the Company completes in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

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 16. Goodwill impairment, if any, is measured by 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 goodwill of the reporting unit is not impaired. If the carrying value of a reporting unit exceeds its fair value, the Company must record an impairment loss for the amount that the carrying value of the reporting unit, including goodwill, exceeds the fair value of the reporting unit. For the years ended December 31, 2019, 2018 and 2017, there were no impairment losses recorded. At December 31, 2019, 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, risk adjusted capital cost, 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 risk adjusted capital cost at each reporting unit. Risk adjusted capital cost, which varies by reporting unit and was in the range of 4 percent to 9 percent was utilized in the goodwill impairment test performed in the fourth quarter of 2019. The goodwill impairment test also utilizes a long-term growth rate projection, which varies by reporting unit and was in the range of approximately 2 percent to 3 percent in the goodwill impairment test performed in the fourth quarter of 2019. Under the market approach, the Company estimates fair value using various multiples derived from 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 a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The electric and natural gas distribution segments generate revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. These segments establish a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Company's utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable state's tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The pipeline and midstream segment generates revenue from providing natural gas transportation, gathering and underground storage services, as well as other energy-related services to both third parties and internal customers, largely the natural gas distribution segment. The pipeline and midstream segment establishes a contract with a customer based upon the customer's request for firm or interruptible natural gas transportation, storage or gathering service(s). The contract identifies an obligation for the segment to provide the requested service(s) in exchange for consideration from the customer over a specified term. Depending on the type of service(s) requested and contracted, the service provided may include transporting, gathering or storing an identified quantity of natural gas and/or standing ready to deliver or store an identified quantity of natural gas. Natural gas transportation, gathering and storage revenues are based on fixed rates, which may include reservation fees and/or per-unit commodity rates. The services provided by the segment are generally treated as single performance obligations satisfied over time simultaneous to when the service is provided and revenue is recognized. Rates for the segment's regulated services are based on its FERC approved tariff or customer negotiated rates, and rates for its non-regulated services are negotiated with its customers and set forth in the contract. For contracts governed by the company's tariff, amounts are billed on or before the ninth business day of the following month and the amount is due within 12 days of receipt of the invoice. For gathering contracts not governed by the tariff, amounts are due within 20 days of invoice receipt. For other contracts not governed by the tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The construction materials and contracting segment generates revenue from contracting services and construction materials sales. This segment focuses on the vertical integration of its contracting services with its construction materials to support the aggregate based product lines. This segment provides contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes integrating a set of services and related construction materials into a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include liquidated damages; performance bonuses or incentives and penalties; claims; unapproved/unpriced change orders; and index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using an input method based on the cost-to-cost measure of progress on a project. This is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction materials to third parties and internal customers. The contract for material sales is the use of a sales order or an invoice, which includes the pricing and payment terms. All material contracts contain a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The construction services segment generates revenue from specialty contracting services which also includes the sale of construction equipment and other supplies. This segment provides specialty contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes multiple promised goods and services in a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include claims, unapproved/unpriced change orders, bonuses, incentives, penalties and liquidated damages. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction equipment and other supplies to third parties and internal customers. The contract for these sales is the use of a sales order or invoice, which includes the pricing and payment terms. All such contracts include a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered.

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.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 36 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $23.8 million and $30.0 million at December 31, 2019 and 2018, respectively, which is included in other accrued liabilities on the Consolidated Balance Sheets. Natural gas costs recoverable through rate adjustments were $89.2 million and $42.7 million at December 31, 2019 and 2018, respectively, which is included in prepayments and other current assets and deferred charges and other assets - other on the Consolidated Balance Sheets.

Stock-based compensation

The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

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 per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of nonvested performance share awards and restricted stock units. Common stock outstanding includes issued shares less shares held in treasury. Earnings on common stock was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2019	2018	2017
		(In thousands)	
Weighted average common shares outstanding - basic	**198,612**	195,720	195,304
Effect of dilutive performance share awards	**14**	430	383
Weighted average common shares outstanding - diluted	**198,626**	196,150	195,687
Shares excluded from the calculation of diluted earnings per share	**164**	10	—

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; revenue recognized using the cost-to-cost measure of progress for contracts; uncollectible accounts; environmental and other loss contingencies; regulatory assets expected to be recovered in rates charged to customers; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; lease classification; present value of right-of-use assets and lease liabilities; 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

ASU 2016-02 - Leases In February 2016, the FASB issued this ASU guidance relating to ASC 842 - *Leases*. The guidance required lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remained 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 required additional disclosures, both quantitative and qualitative, related to operating and financing leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company adopted the standard on January 1, 2019.

In July 2018, the FASB issued ASU 2018-11 - *Leases: Targeted Improvements*, an accounting standard update to ASU 2016-02. This ASU provided an entity the option to adopt the guidance using one of two modified retrospective approaches. An entity could adopt the guidance using the modified retrospective transition approach beginning in the earliest year presented in the financial statements. This method of adoption would have required the restatement of prior periods reported and the presentation of lease disclosures under the new guidance for all periods reported. The additional transition method of adoption, introduced by ASU 2018-11, allowed entities the option to apply the guidance on the date of adoption by recognizing a cumulative effect adjustment to retained earnings during the period of adoption and did not require prior comparative periods to be restated.

The Company adopted the standard on January 1, 2019, utilizing the additional transition method of adoption applied on the date of adoption and the practical expedient that allowed the Company to not reassess whether an expired or existing contract contained a lease, the classification of leases or initial direct costs. The Company did not identify any cumulative effect adjustments. The Company also adopted a short-term leasing policy as the lessee where leases with a term of 12 months or less are not included on the Consolidated Balance Sheet.

As a practical expedient, a lessee may choose not to separate nonlease components from lease components and instead account for lease and nonlease components as a single lease component. The election shall be made by asset class. The Company has elected to adopt the lease/nonlease component practical expedient for all asset classes as the lessee. The Company did not elect the practical expedient to use hindsight when assessing the lease term or impairment of right-of-use assets for the existing leases on the date of adoption.

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 has adopted this practical expedient.

The Company formed a lease implementation team to review and assess existing contracts to identify and evaluate those containing leases. Additionally, the team implemented new and revised existing software to meet the reporting and disclosure requirements of the standard. The Company also assessed the impact the standard had on its processes and internal controls and identified new and updated existing internal controls and processes to ensure compliance with the new lease standard; such modifications were not deemed to be significant. During the assessment phase, the Company used various surveys, reconciliations and analytic methodologies to ensure the completeness of the lease inventory. The Company determined that most of the current operating leases were subject to the guidance and were recognized as operating lease liabilities and right-of-use assets on the Consolidated Balance Sheet upon adoption. On January 1, 2019, the Company recorded approximately $112 million to right-of-use assets and lease liabilities as a result of the initial adoption of the guidance. In addition, the Company evaluated the impact the new guidance had on lease contracts where the Company is the lessor and determined it did not have a significant impact to the Company's financial statements.

ASU 2017-04 - 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 Company early adopted the guidance on a prospective basis beginning with the preparation of its 2019 goodwill impairment test in the fourth quarter of 2019. The adoption of the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures.

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August 2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The Company adopted the guidance effective January 1, 2019, on a prospective basis. The adoption of the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures.

Recently issued accounting standards not yet adopted

ASU 2016-13 - Measurement of Credit Losses on Financial Instruments In June 2016, the FASB issued guidance on the measurement of credit losses on certain financial instruments. The guidance introduces a new impairment model known as the current expected credit loss model that will replace the incurred loss impairment methodology currently included under GAAP. This guidance requires entities to present certain investments in debt securities, trade accounts receivable and other financial assets at their net carrying value of the amount expected to be collected on the financial statements. The Company adopted the guidance on January 1, 2020.

The Company formed an implementation team to review and assess existing financial assets to identify and evaluate the financial assets subject to the new current expected credit loss model. The Company assessed the impact of the guidance on its processes and internal controls and has identified and updated existing internal controls and processes to ensure compliance with the new guidance; such modifications were deemed insignificant. During the assessment phase, the Company completed checklists to identify the complete portfolio of assets subject to the current expected credit loss model. The Company determined the guidance did not have a material impact on its results of operations, financial position, cash flows or disclosures and did not record a material cumulative effect adjustment upon adoption.

ASU 2018-13 - Changes to the Disclosure Requirements for Fair Value Measurement In August 2018, the FASB issued guidance on modifying the disclosure requirements on fair value measurements as part of the disclosure framework project. The guidance modifies, among other things, the disclosures required for Level 3 fair value measurements, including the range and weighted average of significant unobservable inputs. The guidance removes, among other things, the disclosure requirement to disclose transfers between Levels 1 and 2. The guidance will be effective for the Company on January 1, 2020, including interim periods, with early adoption permitted. Level 3 fair value measurement disclosures should be applied prospectively while all other amendments should be applied retrospectively. The Company continues to evaluate the effects the adoption of the new guidance will have on its disclosures in the first quarter of 2020.

ASU 2018-14 - Changes to the Disclosure Requirements for Defined Benefit Plans In August 2018, the FASB issued guidance on modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans as part of the disclosure framework project. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The guidance adds, among other things, the requirement to include an explanation for significant gains and losses related to changes in benefit obligations for the period. The guidance removes, among other things, the disclosure requirement to disclose the amount of net periodic benefit costs to be amortized over the next fiscal year from accumulated other comprehensive income (loss) and the effects a one percentage point change in assumed health care cost trend rates will have on certain benefit components. The guidance will be effective for the Company on January 1, 2021, and must be applied on a retrospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2019-12 - Simplifying the Accounting for Income Taxes In December 2019, the FASB issued guidance on simplifying the accounting for income taxes by removing certain exceptions in ASC 740 and providing simplification amendments. The guidance removes exceptions on intraperiod tax allocations and reporting and provides simplification on accounting for franchise taxes, tax basis goodwill and tax law changes. The guidance will be effective for the Company on January 1, 2021, with early adoption permitted. Transition requirements vary among the exceptions and amendments which include retrospective, modified retrospective and prospective application. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

Variable interest entities

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

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

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

Accumulated other comprehensive income (loss)

The Company's accumulated other comprehensive income (loss) is comprised of losses on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gain (loss) on available-for-sale investments.

The after-tax changes in the components of accumulated other comprehensive loss at December 31, 2019, 2018 and 2017, were as follows:

	Net Unrealized 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)		
At December 31, 2017	$ (1,934)	$ (35,163)	$ (155)	$ (82)	$ (37,334)
Other comprehensive income (loss) before reclassifications	—	4,441	(61)	(144)	4,236
Amounts reclassified from accumulated other comprehensive loss	162	2,173	249	131	2,715
Net current-period other comprehensive income (loss)	162	6,614	188	(13)	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(389)	(7,520)	(33)	(17)	(7,959)
At December 31, 2018	(2,161)	(36,069)	—	(112)	(38,342)
Other comprehensive income (loss) before reclassifications	—	(6,151)	—	134	(6,017)
Amounts reclassified from accumulated other comprehensive loss	731	1,486	—	40	2,257
Net current-period other comprehensive income (loss)	731	(4,665)	—	174	(3,760)
At December 31, 2019	**$ (1,430)**	**$ (40,734)**	**$ —**	**$ 62**	**$ (42,102)**

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Consolidated Statements of Income. The reclassifications for the years ended December 31 were as follows:

	2019	2018	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income	**$ (591)**	$ (591)	Interest expense
	(140)	429	Income taxes
	(731)	(162)	
Amortization of postretirement liability losses included in net periodic benefit cost	**(1,962)**	(2,894)	Other income
	476	721	Income taxes
	(1,486)	(2,173)	
Reclassification adjustment for foreign currency translation adjustment included in net income	**—**	(324)	Other income
	—	75	Income taxes
	—	(249)	
Reclassification adjustment for loss on available-for-sale investments included in net income	**(50)**	(166)	Other income
	10	35	Income taxes
	(40)	(131)	
Total reclassifications	**$ (2,257)**	$ (2,715)	

Note 2 - Revenue from Contracts with Customers

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

As part of the adoption of ASC 606 - *Revenue from Contracts with Customers*, the Company elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is 12 months or less.

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments. For more information on the Company's business segments, see Note 16.

Year ended December 31, 2019	Electric	Natural gas distribution	Pipeline and midstream	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 125,369	$ 483,452	$ —	$ —	$ —	$ —	$ 608,821
Commercial utility sales	141,596	296,835	—	—	—	—	438,431
Industrial utility sales	37,765	26,895	—	—	—	—	64,660
Other utility sales	7,408	—	—	—	—	—	7,408
Natural gas transportation	—	45,449	101,665	—	—	—	147,114
Natural gas gathering	—	—	9,164	—	—	—	9,164
Natural gas storage	—	—	11,708	—	—	—	11,708
Contracting services	—	—	—	1,088,633	—	—	1,088,633
Construction materials	—	—	—	1,627,833	—	—	1,627,833
Intrasegment eliminations*	—	—	—	(525,749)	—	—	(525,749)
Inside specialty contracting	—	—	—	—	1,266,196	—	1,266,196
Outside specialty contracting	—	—	—	—	531,882	—	531,882
Other	35,574	12,726	17,687	—	131	16,551	82,669
Intersegment eliminations	—	—	(56,252)	(1,066)	(3,370)	(16,461)	(77,149)
Revenues from contracts with customers	347,712	865,357	83,972	2,189,651	1,794,839	90	5,281,621
Revenues out of scope	4,013	(135)	220	—	51,057	—	55,155
Total external operating revenues	$ 351,725	$ 865,222	$ 84,192	$ 2,189,651	$ 1,845,896	$ 90	$ 5,336,776

* Intrasegment revenues are presented within the construction materials and contracting segment to highlight the focus on vertical integration as this segment sells materials to both third parties and internal customers. Due to consolidation requirements, these revenues must be eliminated against construction materials to arrive at the external operating revenue total for the segment.

Year ended December 31, 2018	Electric	Natural gas distribution	Pipeline and midstream	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 121,477	$ 457,959	$ —	$ —	$ —	$ —	$ 579,436
Commercial utility sales	136,236	276,716	—	—	—	—	412,952
Industrial utility sales	34,353	24,603	—	—	—	—	58,956
Other utility sales	7,556	—	—	—	—	—	7,556
Natural gas transportation	—	43,238	89,159	—	—	—	132,397
Natural gas gathering	—	—	9,159	—	—	—	9,159
Natural gas storage	—	—	11,543	—	—	—	11,543
Contracting services	—	—	—	968,755	—	—	968,755
Construction materials	—	—	—	1,423,068	—	—	1,423,068
Intrasegment eliminations*	—	—	—	(465,969)	—	—	(465,969)
Inside specialty contracting	—	—	—	—	926,875	—	926,875
Outside specialty contracting	—	—	—	—	392,544	—	392,544
Other	31,568	14,579	18,865	—	525	11,259	76,796
Intersegment eliminations	—	—	(50,905)	(669)	(1,681)	(11,052)	(64,307)
Revenues from contracts with customers	331,190	817,095	77,821	1,925,185	1,318,263	207	4,469,761
Revenues out of scope	3,933	6,152	197	—	51,509	—	61,791
Total external operating revenues	$ 335,123	$ 823,247	$ 78,018	$ 1,925,185	$ 1,369,772	$ 207	$ 4,531,552

* Intrasegment revenues are presented within the construction materials and contracting segment to highlight the focus on vertical integration as this segment sells materials to both third parties and internal customers. Due to consolidation requirements, these revenues must be eliminated against construction materials to arrive at the external operating revenue total for the segment.

Contract balances

The timing of revenue recognition may differ from the timing of invoicing to customers. The timing of invoicing to customers does not necessarily correlate with the timing of revenues being recognized under the cost-to-cost method of accounting. Contracts from contracting services are billed as work progresses in accordance with agreed upon contractual terms. Generally, billing to the customer occurs contemporaneous to revenue recognition. A variance in timing of the billings may result in a contract asset or a contract liability. A contract asset occurs when revenues are recognized under the cost-to-cost measure of progress, which exceeds amounts billed on uncompleted contracts. Such amounts will be billed as standard contract terms allow, usually based on various measures of performance or achievement. A contract liability occurs when there are billings in excess of revenues recognized under the cost-to-cost measure of progress on uncompleted contracts. Contract liabilities decrease as revenue is recognized from the satisfaction of the related performance obligation.

The changes in contract assets and liabilities were as follows:

	December 31, 2019	December 31, 2018	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 109,078	$ 104,239	$ 4,839	Receivables, net
Contract liabilities - current	(142,768)	(93,901)	(48,867)	Accounts payable
Contract liabilities - noncurrent	(19)	(135)	116	Deferred credits and other liabilities - other
Net contract assets (liabilities)	$ (33,709)	$ 10,203	$ (43,912)	

	December 31, 2018	December 31, 2017	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 104,239	$ 109,540	$ (5,301)	Receivables, net
Contract liabilities - current	(93,901)	(84,123)	(9,778)	Accounts payable
Contract liabilities - noncurrent	(135)	—	(135)	Deferred credits and other liabilities - other
Net contract assets	$ 10,203	$ 25,417	$ (15,214)	

The Company recognized $89.0 million and $78.6 million in revenue for the years ended December 31, 2019 and 2018, respectively, which was previously included in contract liabilities at December 31, 2018 and 2017, respectively.

The Company recognized a net increase in revenues of $44.1 million and $36.7 million for the years ended December 31, 2019 and 2018, respectively, from performance obligations satisfied in prior periods.

Remaining performance obligations

The remaining performance obligations at the construction materials and contracting and construction services segments include unrecognized revenues, also referred to as backlog, that the Company reasonably expects to be realized. These unrecognized revenues can include: projects that have a written award, a letter of intent, a notice to proceed, an agreed upon work order to perform work on mutually accepted terms and conditions and change orders or claims to the extent management believes additional contract revenues will be earned and are deemed probable of collection. Excluded from remaining performance obligations are potential orders under master service agreements. The remaining performance obligations at the pipeline and midstream segment include firm transportation and storage contracts with fixed pricing and fixed volumes.

At December 31, 2019, the Company's remaining performance obligations were $2.0 billion. The Company expects to recognize the following revenue amounts in future periods related to these remaining performance obligations: $1.5 billion within the next 12 months or less; $229.4 million within the next 13 to 24 months; and $259.3 million thereafter.

The majority of the Company's construction contracts have an original duration of less than two years. The Company's firm transportation and firm storage contracts have weighted average remaining durations of approximately five and three years, respectively.

Note 3 - Business Combinations

The acquisitions below were accounted for as business combinations in accordance with ASC 805 - *Business Combinations.* The results of the acquired businesses have been included in the Company's Consolidated Financial Statements beginning on the acquisition date. Pro forma financial amounts reflecting the effects of the business combinations are not presented, as none of these business combinations were material to the Company's financial position or results of operations.

For all business combinations, the Company preliminarily allocates the purchase price of the acquisitions to the assets acquired and liabilities assumed based on their estimated fair values as of the acquisition dates and are considered provisional until final fair values are determined or the measurement period has passed. The Company expects to record adjustments as it accumulates the information needed to estimate the fair value of assets acquired and liabilities assumed, including working capital balances, estimated fair value of identifiable intangible assets, property, plant and equipment, total consideration and goodwill. The excess of the purchase price over the aggregate fair values is recorded as goodwill. The Company calculated the fair value of the assets acquired in 2019 and 2018 using a market or cost approach (or a combination of both). Fair values for some of the assets were determined based on Level 3 inputs including estimated future cash flows, discount rates, growth rates, sales projections, retention rates and terminal values, all of which require significant management judgment and are susceptible to change. The final fair value of the net assets acquired may result in adjustments to the assets and liabilities, including goodwill, and will be made as soon as practical, but no later than one year from the respective acquisition dates. Any subsequent measurement period adjustments are not expected to have a material impact on the Company's results of operations. The discount rate used in calculating the fair value of the common stock issued was determined by a Black-Scholes-Merton model. The model used Level 2 inputs including risk-free interest rate, volatility range and dividend yield.

The acquisitions are also subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the business as of the closing date. The amounts included in the Consolidated Balance Sheets for these adjustments are considered provisional until final settlement has occurred.

The following are the acquisitions made during 2019 and 2018 at the construction materials and contracting segment:

- In December 2019, the Company acquired Roadrunner Ready Mix, Inc., a provider of ready-mixed concrete in Idaho.
- In March 2019, the Company acquired Viesko Redi-Mix, Inc., a provider of ready-mixed concrete in Oregon.
- In October 2018, the Company acquired Sweetman Construction Company, a provider of aggregates, asphalt and ready-mixed concrete in South Dakota.
- In July 2018, the Company acquired Molalla Redi-Mix and Rock Products, Inc., a producer of ready-mixed concrete in Oregon.
- In June 2018, the Company acquired Tri-City Paving, Inc., a general contractor and aggregate, asphalt and ready-mixed concrete supplier in Minnesota.
- In April 2018, the Company acquired Teevin & Fischer Quarry, LLC, an aggregate producer that provides crushed rock and gravel to construction and retail customers in Oregon.

In addition to the above acquisitions, in September 2019, the Company purchased the assets of Pride Electric, Inc., an electrical construction company in Washington. The results of Pride Electric, Inc. are included in the constructions services segment.

In 2019, the gross aggregate consideration for acquisitions was $56.8 million, subject to certain adjustments, and includes $1.2 million of debt assumed. The amounts allocated to the aggregated assets acquired and liabilities assumed during 2019 were as follows: $15.8 million to current assets; $16.7 million to property, plant and equipment; $23.1 million to goodwill; $6.7 million to other intangible assets; $500,000 to deferred charges and other assets - other; $5.9 million to current liabilities and $100,000 to deferred credits and other liabilities - other. At December 31, 2019, the purchase price adjustments for Viesko Redi-Mix, Inc. have been settled and no material adjustments were made to the provisional accounting. Purchase price allocations for Pride Electric, Inc. and Roadrunner Ready Mix, Inc. are preliminary and will be finalized within one year of the respective acquisition dates. The Company issued debt and equity securities to finance these acquisitions.

In 2018, the gross aggregate consideration for acquisitions was $168.1 million in cash, subject to certain adjustments, and 721,610 shares of common stock with a market value of $20.3 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration was discounted to a fair value of approximately $18.2 million, as reflected in the Company's financial statements. In addition to the issuance of the Company's equity securities, the Company issued debt to finance these acquisitions.

During the third quarter of 2019, the Company finalized its valuation of the assets acquired and liabilities assumed in conjunction with the acquisition in 2018 of Sweetman Construction Company. As a result, measurement period adjustments were made to the previously disclosed provisional fair values. At December 31, 2019, the purchase price adjustments for all business combinations that occurred in 2018 had been finalized. These adjustments did not have a material impact on the Company's consolidated results of operations. The aggregate total consideration for the 2018 acquisitions and the final amounts allocated to the assets acquired and liabilities assumed were as follows:

	December 31, 2018	Measurement Period Adjustments	**December 31, 2019**
		(In thousands)	
Assets			
Current assets:			
Receivables, net	$ 18,984	$ —	**$ 18,984**
Inventories	10,329	(228)	**10,101**
Other current assets	515	(14)	**501**
Total current assets	29,828	(242)	**29,586**
Property, plant and equipment	131,766	6,669	**138,435**
Deferred charges and other assets:			
Goodwill	33,131	(6,669)	**26,462**
Other intangible assets, net	8,227	—	**8,227**
Other	927	—	**927**
Total deferred charges and other assets	42,285	(6,669)	**35,616**
Total assets acquired	$ 203,879	$ (242)	**$ 203,637**
Liabilities			
Current liabilities	$ 11,122	$ (242)	**$ 10,880**
Deferred credits and other liabilities:			
Asset retirement obligation	914	—	**914**
Deferred income taxes	5,565	—	**5,565**
Total deferred credits and other liabilities	6,479	—	**6,479**
Total liabilities assumed	$ 17,601	$ (242)	**$ 17,359**
Total consideration (fair value)	$ 186,278	$ —	**$ 186,278**

For the years ended December 31, 2019 and 2018, costs incurred for acquisitions were $655,000 and $1.5 million, respectively, and are included in operation and maintenance expense on the Consolidated Statements of Income.

Note 4 - 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 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. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

On June 27, 2016, the Company sold Dakota Prairie Refining to Tesoro. During 2015 and 2016, the Company sold substantially all of Fidelity's oil and natural gas assets. In July 2018, the Company completed the sale of a majority of the remaining property, plant and equipment of Fidelity. The sales of Dakota Prairie Refining and Fidelity were part of the Company's strategic plan to grow its capital investments in the remaining business segments, reduce exposure to commodity pricing and to focus on creating a greater long-term value.

At December 31, 2019 and 2018, the Company's deferred tax assets included in assets held for sale of $1.3 million and $1.9 million, respectively, were largely comprised of state alternative minimum tax credits.

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

	2019	2018
	(In thousands)	
Assets		
Current assets:		
Receivables, net	**$ 425**	$ 430
Total current assets held for sale	**425**	430
Noncurrent assets:		
Deferred income taxes	**1,265**	1,926
Other	**161**	161
Total noncurrent assets held for sale	**1,426**	2,087
Total assets held for sale	**$ 1,851**	$ 2,517
Liabilities		
Current liabilities:		
Accounts payable	**$ —**	$ 80
Taxes payable	**1,279**	1,451
Other accrued liabilities	**2,232**	2,470
Total current liabilities held for sale	**3,511**	4,001
Total liabilities held for sale	**$ 3,511**	$ 4,001

The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations to the after-tax income (loss) from discontinued operations on the Consolidated Statements of Income for the years ended December 31 were as follows:

	2019	2018	2017
		(In thousands)	
Operating revenues	**$ 103**	$ (459)	$ 465
Operating expenses	**290**	921	(4,607)
Operating income (loss)	**(187)**	(1,380)	5,072
Other income (expense)	**—**	12	(13)
Interest expense	**—**	575	250
Income (loss) from discontinued operations before income taxes	**(187)**	(1,943)	4,809
Income taxes*	**(474)**	(4,875)	8,592
Income (loss) from discontinued operations	**$ 287**	$ 2,932	$ (3,783)

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

Note 5 - Leases

Most of the leases the Company enters into are for equipment, buildings, easements and vehicles as part of their ongoing operations. The Company also leases certain equipment to third parties through its utility and construction services segments. The Company determines if an arrangement contains a lease at inception of a contract and accounts for all leases in accordance with ASC 842 - *Leases.* For more information on the adoption of ASC 842, see Note 1.

The recognition of leases requires the Company to make estimates and assumptions that affect the lease classification and the assets and liabilities recorded. The accuracy of lease assets and liabilities reported on the Consolidated Financial Statements depends on, among other things, management's estimates of interest rates used to discount the lease assets and liabilities to their present value, as well as the lease terms based on the unique facts and circumstances of each lease.

Lessee accounting

The leases the Company has entered into as part of its ongoing operations are considered operating leases and are recognized on the Consolidated Balance Sheets as right-of-use assets, current lease liabilities and, if applicable, noncurrent lease liabilities. The corresponding lease costs are included in operation and maintenance expense on the Consolidated Statements of Income.

Generally, the leases for vehicles and equipment have a term of five years or less and buildings and easements have a longer term of up to 35 years or more. To date, the Company does not have any residual value guarantee amounts probable of being owed to a lessor, financing leases or material agreements with related parties.

The following tables provide information on the Company's operating leases at and for the year ended December 31, 2019:

	(In thousands)
Lease costs:	
Operating lease cost	$ **43,759**
Variable lease cost	**1,555**
Short-term lease cost	**120,030**
Total lease costs	$ **165,344**

	(Dollars in thousands)
Weighted average remaining lease term	**3.13 years**
Weighted average discount rate	**4.41%**
Cash paid for amounts included in the measurement of lease liabilities	$ **43,477**

The reconciliation of the future undiscounted cash flows to the operating lease liabilities presented on the Consolidated Balance Sheet at December 31, 2019, was as follows:

	(In thousands)
2020	$ 35,156
2021	24,893
2022	16,932
2023	10,227
2024	7,368
Thereafter	47,926
Total	142,502
Less discount	27,096
Total operating lease liabilities	$ 115,406

The undiscounted annual minimum lease payments due under the Company's leases following the previous lease accounting standard as of December 31, 2018, were as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Operating leases	$ 37,740	$ 26,255	$ 17,868	$ 11,647	$ 7,278	$ 49,098

Lessor accounting

The Company leases certain equipment to third parties, which are considered operating leases. The Company recognized revenue from operating leases of $51.5 million for the year ended December 31, 2019.

The majority of the Company's operating leases are short-term leases of less than 12 months. At December 31, 2019, the Company had $11.3 million of lease receivables with a majority due within 12 months or less.

Note 6 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2019, were as follows:

	Balance at January 1, 2019	Goodwill Acquired During the Year	Measurement Period Adjustments	Balance at December 31, 2019
		(In thousands)		
Natural gas distribution	$ 345,736	$ —	$ —	$ 345,736
Construction materials and contracting	209,421	14,482	(6,669)	217,234
Construction services	109,765	8,623	—	118,388
Total	$ 664,922	$ 23,105	$ (6,669)	$ 681,358

The changes in the carrying amount of goodwill for the year ended December 31, 2018, were as follows:

	Balance at January 1, 2018	Goodwill Acquired During the Year	Measurement Period Adjustments	Balance at December 31, 2018
		(In thousands)		
Natural gas distribution	$ 345,736	$ —	$ —	$ 345,736
Construction materials and contracting	176,290	33,131	—	209,421
Construction services	109,765	—	—	109,765
Total	$ 631,791	$ 33,131	$ —	$ 664,922

During 2019 and 2018, the Company completed three and four business combinations, respectively, and the results of these acquisitions have been included in the Company's construction materials and contracting and construction services segments. These business combinations increased the construction materials and contracting segment's goodwill balance at December 31, 2019 and 2018, respectively, and increased the construction services segment's goodwill balance at December 31, 2019, as noted in the previous tables. At December 31, 2019 and 2018, the impacts of these business combinations on other intangible assets resulted in an increase of $6.8 million and $8.2 million, respectively. For more information related to these business combinations, see Note 3.

Other amortizable intangible assets at December 31 were as follows:

	2019	2018
	(In thousands)	
Customer relationships	**$ 17,958**	$ 22,720
Less accumulated amortization	**6,268**	13,535
	11,690	9,185
Noncompete agreements	**3,439**	2,605
Less accumulated amortization	**1,957**	1,956
	1,482	649
Other	**8,094**	6,458
Less accumulated amortization	**6,020**	5,477
	2,074	981
Total	**$ 15,246**	$ 10,815

Amortization expense for amortizable intangible assets for the years ended December 31, 2019, 2018 and 2017, was $2.4 million, $1.2 million and $2.0 million, respectively. The amounts of estimated amortization expense for identifiable intangible assets as of December 31, 2019, were:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Amortization expense	$ 3,365	$ 2,016	$ 1,968	$ 1,924	$ 1,610	$ 4,363

Note 7 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *		2019		2018
			(In thousands)		
Regulatory assets:					
Pension and postretirement benefits (a)	(e)	$	**157,069**	$	165,898
Natural gas costs recoverable through rate adjustments (a) (b)	Up to 3 years		**89,204**		42,652
Asset retirement obligations (a)	Over plant lives		**66,000**		60,097
Plants to be retired (a)	-		**32,931**		—
Cost recovery mechanisms (a) (b)	Up to 3 years		**19,396**		17,948
Manufactured gas plant sites remediation (a)	-		**15,347**		17,068
Taxes recoverable from customers (a)	Over plant lives		**11,486**		11,946
Conservation programs (a) (b)	Up to 3 years		**7,405**		7,494
Long-term debt refinancing costs (a)	Up to 18 years		**4,286**		4,898
Costs related to identifying generation development (a)	Up to 7 years		**2,052**		2,508
Other (a) (b)	Up to 19 years		**12,221**		9,608
Total regulatory assets		$	**417,397**	$	340,117
Regulatory liabilities:					
Taxes refundable to customers (c) (d)		$	**249,506**	$	277,833
Plant removal and decommissioning costs (c)			**173,722**		173,143
Natural gas costs refundable through rate adjustments (d)			**23,825**		29,995
Pension and postretirement benefits (c)			**18,065**		15,264
Other (c) (d)			**25,187**		25,197
Total regulatory liabilities		$	**490,305**	$	521,432
Net regulatory position		$	**(72,908)**	$	(181,315)

* 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, 2019 and 2018, approximately $276.5 million and $313.5 million, respectively, of regulatory assets were not earning a rate of return.

During the first quarter of 2019 and the fourth quarter of 2018, the Company experienced increased natural gas costs in certain jurisdictions where it supplies natural gas. The Company has recorded these natural gas costs as regulatory assets as they are expected to be recovered from customers, as discussed in Note 19.

In February 2019, the Company announced that it intends to retire three aging coal-fired electric generating units in early 2021 and early 2022. The Company has accelerated the depreciation related to these facilities in property, plant and equipment and has recorded the difference between the accelerated depreciation, in accordance with GAAP, and the depreciation approved for rate-making purposes as regulatory assets. The Company expects to recover the regulatory assets related to the plants to be retired in future rates.

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 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified defined 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 $87.0 million and $73.8 million at December 31, 2019 and 2018, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2019 and 2017, were $13.2 million and $9.3 million, respectively. The net unrealized loss on these investments for the year ended December 31, 2018, was $3.6 million. The change in fair value, which is considered part of the cost of the plan, is classified in other income 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, 2019	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 9,804	$ 87	$ 10	$ 9,881
U.S. Treasury securities	1,228	1	—	1,229
Total	$ 11,032	$ 88	$ 10	$ 11,110

December 31, 2018	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,473	$ 21	$ 162	$ 10,332
U.S. Treasury securities	179	—	—	179
Total	$ 10,652	$ 21	$ 162	$ 10,511

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 fair value 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, 2019 and 2018, 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, 2019, 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, 2019
		(In thousands)		
Assets:				
Money market funds	$ —	$ 8,440	$ —	$ 8,440
Insurance contract*	—	87,009	—	87,009
Available-for-sale securities:				
Mortgage-backed securities	—	9,881	—	9,881
U.S. Treasury securities	—	1,229	—	1,229
Total assets measured at fair value	$ —	$ 106,559	$ —	$ 106,559

* The insurance contract invests approximately 51 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 12 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at December 31, 2018, 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, 2018
		(In thousands)		
Assets:				
Money market funds	$ —	$ 10,799	$ —	$ 10,799
Insurance contract*	—	73,838	—	73,838
Available-for-sale securities:				
Mortgage-backed securities	—	10,332	—	10,332
U.S. Treasury securities	—	179	—	179
Total assets measured at fair value	$ —	$ 95,148	$ —	$ 95,148

* The insurance contract invests approximately 53 percent in fixed-income investments, 21 percent in common stock of large-cap companies, 11 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 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.

In the second quarter of 2019, the Company reviewed a non-utility investment at its electric and natural gas distribution segments for impairment. This was a cost-method investment and was written down to zero using the income approach to determine its fair value, requiring the Company to record a write-down of $2.0 million, before tax. The fair value of this investment was categorized as Level 3 in the fair value hierarchy. The reduction is reflected in investments on the Consolidated Balance Sheet, as well as within other income on the Consolidated Statement of Income.

The Company performed a fair value assessment of the assets acquired and liabilities assumed in the business combinations that occurred during 2019 and 2018. For more information on these Level 2 and Level 3 fair value measurements, see Note 3.

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 categorized as Level 2 in the fair value hierarchy and 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:

	2019	2018
	(In thousands)	
Carrying Amount	**$ 2,243,107**	$ 2,108,695
Fair Value	**$ 2,418,631**	$ 2,183,819

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

Note 9 - Debt

Certain debt instruments of the Company's subsidiaries, including those discussed later, contain restrictive and financial covenants and cross-default provisions. In order to borrow under the debt agreements, the subsidiary companies must be in compliance with the applicable covenants and certain other conditions, all of which the subsidiaries, as applicable, were in compliance with at December 31, 2019. In the event the 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's subsidiaries:

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2019		Amount Outstanding at December 31, 2018		Letters of Credit at December 31, 2019		Expiration Date
							(In millions)				
Montana-Dakota Utilities Co.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 118.6	(b)	$ 48.5		$ —		12/19/24
Cascade Natural Gas Corporation	Revolving credit agreement		$ 100.0	(c)	$ 64.6		$ 53.8		$ 2.2	(d)	6/7/24
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 24.5		$ 56.3		$ 1.4	(d)	6/7/24
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 600.0		$ 104.3	(b)	$ 289.6	(b)	$ —		12/19/24

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Montana-Dakota on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the revolving credit agreement at December 31, 2019, and $48.5 million was outstanding at December 31, 2018.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $125.0 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 $700.0 million). There were no amounts outstanding under the revolving credit agreement.

The 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, Montana-Dakota 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 certain operations of the Company's subsidiaries.

The following includes information related to the preceding table.

Long-term debt

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

	Weighted Average Interest Rate at December 31, 2019	2019	2018
		(In thousands)	
Senior Notes due on dates ranging from October 22, 2022 to November 18, 2059	**4.45%**	**$ 1,850,000**	$ 1,381,000
Commercial paper supported by revolving credit agreements	**2.04%**	**222,900**	338,100
Term Loan Agreement due on September 3, 2032	**2.00%**	**9,100**	209,800
Credit agreements due on June 7, 2024	**4.40%**	**89,050**	110,100
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 15, 2021 to November 30, 2038	**4.48%**	**29,117**	25,229
Less unamortized debt issuance costs		**7,010**	5,207
Less discount		**50**	327
Total long-term debt		**2,243,107**	2,108,695
Less current maturities		**16,540**	251,854
Net long-term debt		**$ 2,226,567**	$ 1,856,841

Montana-Dakota On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same. For more information on the reorganization, see Note 1.

On December 19, 2019, Montana-Dakota amended and restated its revolving credit agreement extending the maturity date to December 19, 2024. Montana-Dakota's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The credit agreement contains customary covenants and provisions, including covenants of Montana-Dakota not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) 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.

On July 24, 2019, Montana-Dakota entered into a $200.0 million note purchase agreement with maturity dates ranging from October 17, 2039 to November 18, 2059, at a weighted average interest rate of 3.95 percent. The agreement contains customary covenants and provisions, including a covenant of Montana-Dakota not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent.

Montana-Dakota's ratio of total debt to total capitalization at December 31, 2019, was 52 percent.

Cascade On June 7, 2019, Cascade amended its revolving credit agreement to increase the borrowing capacity to $100.0 million and extend the maturity date to June 7, 2024. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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

On June 13, 2019, Cascade issued $75.0 million of senior notes with maturity dates ranging from June 13, 2029 to June 13, 2049, at a weighted average interest rate of 3.93 percent. The 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.

Cascade's ratio of total debt to total capitalization at December 31, 2019, was 53 percent.

Intermountain On June 7, 2019, Intermountain amended its revolving credit agreement to extend the maturity date to June 7, 2024. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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

On June 13, 2019, Intermountain issued $50.0 million of senior notes with maturity dates ranging from June 13, 2029 to June 13, 2049, at a weighted average interest rate of 3.92 percent. The 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.

Intermountain's ratio of total debt to total capitalization at December 31, 2019, was 50 percent.

Centennial On December 19, 2019, Centennial amended and restated its revolving credit agreement to increase the borrowing capacity to $600.0 million and extend the maturity date to December 19, 2024. 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 contains 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. 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.

On April 4, 2019, Centennial issued $150.0 million of senior notes with maturity dates ranging from April 4, 2029 to April 4, 2034, at a weighted average interest rate of 4.60 percent. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of total debt to total capitalization to be greater than 60 percent.

Centennial's ratio of total debt to total capitalization at December 31, 2019, was 34 percent.

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 On July 26, 2019, WBI Energy Transmission amended its uncommitted note purchase and private shelf agreement to increase capacity to $300.0 million and extend the issuance period to May 16, 2022. On December 16, 2019, WBI Energy Transmission issued $45.0 million of senior notes under the private shelf agreement with a maturity date of December 16, 2034, at an interest rate of 4.17 percent. WBI Energy Transmission had $170.0 million of notes outstanding at December 31, 2019, which reduced the remaining capacity under this uncommitted private shelf agreement to $130.0 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.

WBI Energy Transmission's ratio of total debt to total capitalization at December 31, 2019, was 40 percent.

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, 2019, were as follows:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Long-term debt maturities	$ 16,540	$ 1,528	$ 148,021	$ 77,921	$ 373,372	$ 1,632,785

Note 10 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, natural gas transmission lines, natural gas storage wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

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

	2019	2018
	(In thousands)	
Balance at beginning of year	**$ 375,553**	$ 341,969
Liabilities incurred	**25,869**	13,424
Liabilities acquired	**486**	1,002
Liabilities settled	**(7,097)**	(3,699)
Accretion expense*	**19,789**	18,242
Revisions in estimates	**2,975**	4,615
Balance at end of year	**$ 417,575**	$ 375,553

* Includes $18.3 million and $16.8 million in 2019 and 2018, respectively, related to regulatory assets.

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 7.

Note 11 - Preferred Stock

The Company currently has 2.0 million shares of preferred stock authorized to be issued with a $100 par value. At December 31, 2019, there were no shares outstanding. At December 31, 2018, there were no shares outstanding. 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 12 - Common Stock

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the dividend amount for the last 29 consecutive years. For the years ended December 31, 2019, 2018 and 2017, dividends declared on common stock were $.8150, $.7950 and $.7750 per common share, respectively. Dividends on common stock are paid quarterly to the stockholders of record less than 30 days prior to the distribution date. For the years ended December 31, 2019, 2018 and 2017, the dividends declared to common stockholders were $162.1 million, $155.7 million and $151.5 million, respectively.

The declaration and payment of dividends of the Company is at the sole discretion of the board of directors. In addition, the Company's subsidiaries 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 3.5 to 1. In addition, certain credit agreements and regulatory limitations of the Company's subsidiaries also contain restrictions on dividend payments. The most restrictive limitation requires the Company's subsidiaries not to permit the ratio of funded debt to capitalization to be greater than 65 percent. Based on this limitation, approximately $1.4 billion of the net assets of the Company's subsidiaries, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2019.

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

On February 22, 2019, the Company entered into a Distribution Agreement with J.P. Morgan Securities LLC and MUFG Securities Americas Inc., as sales agents, with respect to the issuance and sale of up to 10.0 million shares of the Company's common stock in connection with an “at-the-market” offering. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement.

The Company issued 3.6 million shares of common stock for the year ended December 31, 2019, pursuant to the “at-the-market” offering. For the year ended December 31, 2019, the Company received net proceeds of $94.0 million and paid commissions to the sales agents of approximately $950,000 in connection with the sales of common stock under the "at-the-market" offering. The net proceeds were used for capital expenditures and acquisitions. As of December 31, 2019, the Company had remaining capacity to issue up to 6.4 million additional shares of common stock under the "at-the-market" offering program.

The K-Plan provides participants the option to invest in the Company's common stock. For the years ended December 31, 2019, 2018 and 2017, the K-Plan purchased shares of common stock on the open market or issued original issue common stock of the Company. At December 31, 2019, there were 7.3 million shares of common stock reserved for original issuance under the K-Plan.

Note 13 - Stock-Based Compensation

The Company has stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2019, there were 4.6 million remaining shares available to grant under these plans. The Company either purchases shares on the open market or issues new shares of common stock to satisfy the vesting of stock-based awards.

Total stock-based compensation expense (after tax) was $6.5 million, $4.6 million and $2.7 million in 2019, 2018 and 2017, respectively.

As of December 31, 2019, total remaining unrecognized compensation expense related to stock-based compensation was approximately $9.7 million (before income taxes) which will be amortized over a weighted average period of 1.6 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 in 2019, 2018 and 2017. There were 41,644 shares with a fair value of $1.2 million, 38,605 shares with a fair value of $1.0 million and 40,572 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2019, 2018 and 2017, respectively.

Restricted stock awards

In February 2018, the Company granted restricted stock awards under the long-term performance-based incentive plan to certain key employees. The restricted stock awards granted will vest after three years. The grant-date fair value is the market price of the Company's stock on the grant date. At December 31, 2019, the total nonvested shares were 22,838 with a weighted average grant-date fair value of $27.48 per share.

Performance share awards

Since 2003, key employees of the Company have been granted performance share awards each year under the long-term performance-based incentive plan. Entitlement to performance shares is established by either the market condition or the performance metrics and service condition relative to the designated award.

Target grants of performance shares outstanding at December 31, 2019, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2018	2018-2020	246,309
February 2019	2019-2021	327,194

Under the market condition for these performance share awards, participants may earn from zero to 200 percent of the apportioned 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 applicable to the market condition for certain performance shares issued in 2019, 2018 and 2017 were:

	2019	2018	2017
Weighted average grant-date fair value	**$35.07**	$34.55	$24.31
Blended volatility range	**19.50% – 19.69%**	17.87% – 22.14%	22.70% – 25.56%
Risk-free interest rate range	**2.46% – 2.55%**	1.86% – 2.46%	.69% – 1.61%
Weighted average discounted dividends per share	**$2.85**	$2.46	$1.70

Under the performance conditions for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares. The performance conditions are based on the Company's compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion and amortization and the Company's compound annual growth rate in earnings from continuing operations. The weighted average grant-date fair value per share for the performance shares applicable to these performance conditions issued in 2019 and 2018 was $26.25 and $27.48, respectively.

The fair value of the performance shares that vested during the years ended December 31, 2019 and 2017, was $9.7 million and $9.6 million, respectively. There were no performance shares that vested in 2018.

A summary of the status of the performance share awards for the year ended December 31, 2019, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	668,791	$ 23.03
Granted	327,194	30.66
Additional performance shares earned	103,159	14.60
Less:		
Vested	398,919	15.52
Forfeited	126,722	24.31
Nonvested at end of period	573,503	$ 30.81

Note 14 - Income Taxes

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

	2019	2018	2017
		(In thousands)	
United States	**$ 398,532**	$ 317,655	$ 350,064
Foreign	**(87)**	(784)	(37)
Income before income taxes from continuing operations	**$ 398,445**	$ 316,871	$ 350,027

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

	2019	2018	2017
		(In thousands)	
Current:			
Federal	$ **(3,502)**	$ (15,901)	$ 74,272
State	**3,366**	3,651	16,192
	(136)	(12,250)	90,464
Deferred:			
Income taxes:			
Federal	**50,218**	50,755	(24,497)
State	**12,098**	7,206	(864)
Investment tax credit - net	**1,099**	1,774	(62)
	63,415	59,735	(25,423)
Total income tax expense	$ **63,279**	$ 47,485	$ 65,041

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 was deferred under regulatory accounting as the Company worked with the various regulators to determine the amount and timing of amounts to be returned to customers. In the third quarter of 2018, the Company reversed a regulatory liability recorded in 2017 based on a FERC final accounting order being issued, which resulted in a $4.2 million tax benefit.

The changes included in the TCJA were broad and complex. The SEC issued rules that allowed 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 reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

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

	2019	2018
	(In thousands)	
Deferred tax assets:		
Postretirement	**$ 51,075**	$ 51,930
Compensation-related	**37,330**	29,885
Operating lease liabilities	**24,459**	—
Asset retirement obligations	**7,450**	7,083
Customer advances	**7,325**	7,734
Legal and environmental contingencies	**6,601**	6,729
Federal renewable energy credit	**5,343**	8,015
Alternative minimum tax credit carryforward	**—**	13,404
Other	**32,533**	37,347
Total deferred tax assets	**172,116**	162,127
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**511,867**	476,832
Postretirement	**48,927**	44,432
Operating lease right-of-use-assets	**24,436**	—
Intangible asset amortization	**18,930**	17,752
Other	**61,385**	39,712
Total deferred tax liabilities	**665,545**	578,728
Valuation allowance	**13,154**	13,484
Net deferred income tax liability	**$ 506,583**	$ 430,085

As of December 31, 2019 and 2018, the Company had various state income tax net operating loss carryforwards of $149.8 million and $153.2 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $43.7 million and $43.5 million, respectively. Included in the state credits are various regulatory investment tax credits of approximately $37.4 million and $32.2 million at December 31, 2019 and 2018, respectively. The federal income tax credit carryforwards expire in 2040 if not utilized and state income tax credit carryforwards are due to expire between 2020 and 2033. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future.

The following table reconciles the change in the net deferred income tax liability from December 31, 2018, to December 31, 2019, to deferred income tax expense:

	2019
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 76,498**
Deferred taxes associated with other comprehensive loss	**1,631**
Deferred taxes associated with TCJA enactment for regulated activities	**(11,904)**
Other	**(2,810)**
Deferred income tax expense for the period	**$ 63,415**

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,	2019		2018		2017	
	Amount	**%**	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 83,674**	**21.0**	$ 66,543	21.0	$ 122,509	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	**14,029**	**3.5**	12,190	3.8	10,724	3.1
Federal renewable energy credit	**(15,843)**	**(4.0)**	(11,759)	(3.7)	(13,958)	(4.0)
Tax compliance and uncertain tax positions	**(2,739)**	**(.7)**	(2,725)	(.9)	(643)	(.2)
Domestic production deduction	**—**	**—**	—	—	(6,849)	(2.0)
Excess deferred income tax amortization	**(11,904)**	**(3.0)**	(9,319)	(2.9)	(397)	—
TCJA revaluation	**—**	**—**	(5,947)	(1.9)	(47,242)	(13.5)
TCJA revaluation related to accumulated other comprehensive loss balance	**—**	**—**	(42)	—	7,735	2.2
Other	**(3,938)**	**(.9)**	(1,456)	(.4)	(6,838)	(2.0)
Total income tax expense	**$ 63,279**	**15.9**	$ 47,485	15.0	$ 65,041	18.6

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 2015. With few exceptions, as of December 31, 2019, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2015.

For the years ended December 31, 2019, 2018 and 2017, total reserves for uncertain tax positions were not material. The Company recognizes interest and penalties accrued relative to unrecognized tax benefits in income tax expense.

Note 15 - Cash Flow Information

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

	2019	2018	2017
		(In thousands)	
Interest, net*	**$ 93,414**	$ 83,009	$ 79,638
Income taxes paid (refunded), net**	**$ (8,475)**	$ 16,041	$ 112,137

* AFUDC - borrowed was $2.8 million, $2.3 million and $966,000 for the years ended December 31, 2019, 2018 and 2017, respectively.

** Income taxes paid (refunded), including discontinued operations, were $(9.4) million, $5.5 million and $9.7 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Noncash investing and financing transactions at December 31 were as follows:

	2019	2018	2017
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 46,119**	$ 42,355	$ 29,263
Issuance of common stock in connection with acquisition	**$ —**	$ 18,186	$ —
Debt assumed in connection with a business combination	**$ 1,163**	$ —	$ —
Right-of-use assets obtained in exchange for new operating lease liabilities	**$ 54,880**	$ —	$ —

Note 16 - 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.

The construction materials and contracting segment mines, processes and sells construction aggregates (crushed stone, sand and gravel); produces and sells asphalt mix; and supplies ready-mixed concrete. This segment focuses on vertical integration of its contracting services with its construction materials 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, including Alaska and Hawaii.

The construction services segment provides inside and outside specialty contracting services. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and 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. This segment also 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, through its subsidiary InterSource Insurance Company, 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 self-insured layers of the insured Company's general liability, automobile liability, pollution liability and other coverages. Centennial Capital also owns certain real and personal property. In addition, the Other category includes certain assets, liabilities and tax adjustments of the holding company primarily associated with corporate functions and 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 include the results and supporting activities of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. For more information on discontinued operations, see Note 4.

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:

	2019	2018	2017
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	**$ 351,725**	$ 335,123	$ 342,805
Natural gas distribution	**865,222**	823,247	848,388
Pipeline and midstream	**62,357**	54,857	53,566
	1,279,304	1,213,227	1,244,759
Nonregulated operations:			
Pipeline and midstream	**21,835**	23,161	19,602
Construction materials and contracting	**2,189,651**	1,925,185	1,811,964
Construction services	**1,845,896**	1,369,772	1,366,317
Other	**90**	207	709
	4,057,472	3,318,325	3,198,592
Total external operating revenues	**$ 5,336,776**	$ 4,531,552	$ 4,443,351
Intersegment operating revenues:			
Regulated operations:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and midstream	**56,037**	50,580	48,867
	56,037	50,580	48,867
Nonregulated operations:			
Pipeline and midstream	**215**	325	178
Construction materials and contracting	**1,066**	669	565
Construction services	**3,370**	1,681	1,285
Other	**16,461**	11,052	7,165
	21,112	13,727	9,193
Intersegment eliminations	**(77,149)**	(64,307)	(58,060)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 58,721**	$ 50,982	$ 47,715
Natural gas distribution	**79,564**	72,486	69,381
Pipeline and midstream	**21,220**	17,896	16,788
Construction materials and contracting	**77,450**	61,158	55,862
Construction services	**17,038**	15,728	15,739
Other	**2,024**	1,955	2,001
Total depreciation, depletion and amortization	**$ 256,017**	$ 220,205	$ 207,486
Operating income (loss):			
Electric	**$ 64,039**	$ 65,148	$ 79,902
Natural gas distribution	**69,188**	72,336	84,239
Pipeline and midstream	**42,796**	36,128	36,004
Construction materials and contracting	**179,955**	141,426	143,230
Construction services	**126,426**	86,764	81,292
Other	**(1,184)**	(79)	(619)
Total operating income	**$ 481,220**	$ 401,723	$ 424,048

	2019	2018	2017
		(In thousands)	
Interest expense:			
Electric	$ 25,334	$ 25,860	$ 25,377
Natural gas distribution	35,488	30,768	31,234
Pipeline and midstream	7,198	5,964	4,990
Construction materials and contracting	23,792	17,290	14,778
Construction services	5,331	3,551	3,742
Other	1,859	2,762	3,564
Intersegment eliminations	(415)	(1,581)	(897)
Total interest expense	$ 98,587	$ 84,614	$ 82,788
Income taxes:			
Electric	$ (12,650)	$ (6,482)	$ 7,699
Natural gas distribution	1,405	4,075	22,756
Pipeline and midstream	7,219	2,677	12,281
Construction materials and contracting	37,389	28,357	5,405
Construction services	29,973	20,000	25,558
Other	(57)	(1,142)	(1,809)
Intersegment eliminations	—	—	(6,849)
Total income taxes	$ 63,279	$ 47,485	$ 65,041
Earnings on common stock:			
Regulated operations:			
Electric	$ 54,763	$ 47,000	$ 49,366
Natural gas distribution	39,517	37,732	32,225
Pipeline and midstream	28,255	26,905	20,620
	122,535	111,637	102,211
Nonregulated operations:			
Pipeline and midstream	1,348	1,554	(127)
Construction materials and contracting	120,371	92,647	123,398
Construction services	92,998	64,309	53,306
Other	(2,086)	(761)	(1,422)
	212,631	157,749	175,155
Intersegment eliminations (a)	—	—	6,849
Earnings on common stock before income (loss) from discontinued operations	335,166	269,386	284,215
Income (loss) from discontinued operations, net of tax (a)	287	2,932	(3,783)
Earnings on common stock	$ 335,453	$ 272,318	$ 280,432
Capital expenditures:			
Electric	$ 99,449	$ 186,105	$ 109,107
Natural gas distribution	206,799	205,896	146,981
Pipeline and midstream	71,477	70,057	31,054
Construction materials and contracting	190,092	280,396	44,302
Construction services	60,500	25,081	18,630
Other	8,181	1,768	1,850
Total capital expenditures (b)	$ 636,498	$ 769,303	$ 351,924

	2019	2018	2017
		(In thousands)	
Assets:			
Electric (c)	**$ 1,680,194**	$ 1,613,822	$ 1,470,922
Natural gas distribution (c)	**2,574,965**	2,375,871	2,201,081
Pipeline and midstream	**677,482**	616,959	566,295
Construction materials and contracting	**1,684,161**	1,508,032	1,238,696
Construction services	**761,127**	604,798	591,382
Other (d)	**303,279**	266,111	261,419
Assets held for sale	**1,851**	2,517	4,871
Total assets	**$ 7,683,059**	$ 6,988,110	$ 6,334,666
Property, plant and equipment:			
Electric (c)	**$ 2,227,145**	$ 2,148,569	$ 1,982,264
Natural gas distribution (c)	**2,688,123**	2,499,093	2,319,845
Pipeline and midstream	**834,215**	764,959	700,284
Construction materials and contracting	**1,910,562**	1,768,006	1,560,048
Construction services	**213,370**	188,586	177,265
Other	**35,213**	28,108	31,123
Less accumulated depreciation, depletion and amortization	**2,991,486**	2,818,644	2,691,641
Net property, plant and equipment	**$ 4,917,142**	$ 4,578,677	$ 4,079,188

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) Capital expenditures for 2019, 2018 and 2017 include noncash transactions such as the issuance of the Company's equity securities in connection with acquisitions, capital expenditure-related accounts payable and AFUDC, totaling $4.8 million, $33.4 million and $10.5 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 17 - 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 benefit pension plan benefits and accruals for all nonunion and certain union plans were frozen and on June 30, 2015, the remaining union plan was frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits, to an annuity company. The transfer of the benefit payments for these participants reduced the Company's liability and future premiums.

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, were provided the option to choose between a pre-65 comprehensive medical plan coupled with a Medicare supplement or a specified company funded Retiree Reimbursement Account, regardless of when they retire. All other eligible employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire to 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, 2019 and 2018, and amounts recognized in the Consolidated Balance Sheets at December 31, 2019 and 2018, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 391,602**	$ 445,923	**$ 81,201**	$ 91,206
Service cost	**—**	—	**1,142**	1,494
Interest cost	**15,225**	14,591	**2,986**	2,899
Plan participants' contributions	**—**	—	**1,040**	1,282
Actuarial (gain) loss	**40,219**	(32,637)	**2,632**	(10,115)
Benefits paid	**(25,880)**	(36,275)	**(5,387)**	(5,565)
Benefit obligation at end of year	**421,166**	391,602	**83,614**	81,201
Change in net plan assets:				
Fair value of plan assets at beginning of year	**307,809**	354,384	**82,516**	88,739
Actual gain (loss) on plan assets	**58,409**	(21,138)	**15,731**	(2,781)
Employer contribution	**24,926**	10,838	**687**	842
Plan participants' contributions	**—**	—	**1,040**	1,281
Benefits paid	**(25,880)**	(36,275)	**(5,387)**	(5,565)
Fair value of net plan assets at end of year	**365,264**	307,809	**94,587**	82,516
Funded status - over (under)	**$ (55,902)**	$ (83,793)	**$ 10,973**	$ 1,315
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Deferred charges and other assets - other	**$ —**	$ —	**$ 30,475**	20,843
Other accrued liabilities	**—**	—	**647**	660
Deferred credits and other liabilities - other	**55,902**	83,793	**18,855**	18,868
Benefit obligation assets (liabilities) - net amount recognized	**$ (55,902)**	$ (83,793)	**$ 10,973**	$ 1,315
Amounts recognized in accumulated other comprehensive loss:				
Actuarial loss	**$ 27,748**	$ 28,796	**$ 6,118**	$ 6,372
Prior service credit	**—**	—	**(731)**	(848)
Total	**$ 27,748**	$ 28,796	**$ 5,387**	$ 5,524
Amounts recognized in regulatory assets or liabilities:				
Actuarial (gain) loss	**$ 155,484**	$ 159,939	**$ (4,450)**	$ 3,944
Prior service credit	**—**	—	**(8,109)**	(9,390)
Total	**$ 155,484**	$ 159,939	**$ (12,559)**	$ (5,446)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Amounts related to regulated operations are recorded as regulatory assets or liabilities and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets and liabilities, see Note 7.

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:

	2019	2018
	(In thousands)	
Projected benefit obligation	**$ 421,166**	$ 391,602
Accumulated benefit obligation	**$ 421,166**	$ 391,602
Fair value of plan assets	**$ 365,264**	$ 307,809

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		
	2019	2018	2017	**2019**	2018	2017
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	**$ —**	$ —	$ —	**$ 1,142**	$ 1,494	$ 1,508
Interest cost	**15,225**	14,591	16,207	**2,986**	2,899	3,265
Expected return on assets	**(18,236)**	(20,753)	(20,528)	**(4,804)**	(4,866)	(4,641)
Amortization of prior service credit	**—**	—	—	**(1,398)**	(1,394)	(1,371)
Recognized net actuarial loss	**5,548**	7,005	6,355	**353**	640	857
Net periodic benefit cost (credit), including amount capitalized	**2,537**	843	2,034	**(1,721)**	(1,227)	(382)
Less amount capitalized	**—**	—	310	**113**	153	(370)
Net periodic benefit cost (credit)	**2,537**	843	1,724	**(1,834)**	(1,380)	(12)
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive loss:						
Net (gain) loss	**(144)**	991	(1,091)	**(127)**	(1,735)	1,742
Amortization of actuarial loss	**(904)**	(1,084)	(1,040)	**(110)**	(354)	(289)
Amortization of prior service (cost) credit	**—**	—	—	**100**	(220)	161
Total recognized in accumulated other comprehensive loss	**(1,048)**	(93)	(2,131)	**(137)**	(2,309)	1,614
Other changes in plan assets and benefit obligations recognized in regulatory assets or liabilities:						
Net (gain) loss	**189**	8,263	(4,736)	**(8,168)**	(732)	(4,932)
Amortization of actuarial loss	**(4,644)**	(5,921)	(5,315)	**(242)**	(286)	(568)
Amortization of prior service credit	**—**	—	—	**1,297**	1,614	1,210
Total recognized in regulatory assets or liabilities	**(4,455)**	2,342	(10,051)	**(7,113)**	596	(4,290)
Total recognized in net periodic benefit cost (credit), accumulated other comprehensive loss and regulatory assets or liabilities	**$ (2,966)**	$ 3,092	$ (10,458)	**$ (9,084)**	$ (3,093)	$ (2,688)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets or liabilities into net periodic benefit cost in 2020 is $7.2 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets or liabilities into net periodic benefit credit in 2020 are $250,000 and $1.4 million, respectively. Prior service credit 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	
	2019	2018	**2019**	2018
Discount rate	**2.96%**	4.03%	**3.00%**	4.05%
Expected return on plan assets	**6.25%**	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 (credit) for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2019	2018	**2019**	2018
Discount rate	**4.03%**	3.38%	**4.05%**	3.41%
Expected return on plan assets	**6.25%**	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, 2019, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 30 percent equity securities and 70 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

	2019	2018
Health care trend rate assumed for next year	**7.1% – 7.4%**	7.5% – 8.1%
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 Company contributes a flat dollar amount to the monthly premiums which is updated annually on January 1.

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, 2019:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 245	$ (203)
Effect on postretirement benefit obligation	$ 3,751	$ (3,155)

In 2019, the Company contributed an additional $20.0 million to its defined benefit pension plans, which increased the funded status and decreased future expenses for the plans. The Company does not expect to contribute to its defined benefit pension plans and expects to contribute approximately $660,000 to its postretirement benefit plans in 2020.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2019, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2020	$ 24,128	$ 5,024	$ 92
2021	24,432	5,073	86
2022	24,642	5,098	80
2023	24,874	5,091	73
2024	24,924	5,000	65
2025-2029	121,205	24,242	222

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 fair value 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.

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, 2019 and 2018, 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, 2019, 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, 2019
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 26,166	$ —	$ 26,166
Equity securities:				
U.S. companies	14,457	—	—	14,457
International companies	—	938	—	938
Collective and mutual funds*	160,906	58,894	—	219,800
Corporate bonds	—	80,768	—	80,768
Municipal bonds	—	11,828	—	11,828
U.S. Government securities	7,296	2,082	—	9,378
Total assets measured at fair value	$ 182,659	$ 180,676	$ —	$ 363,335

* Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in common stock of large-cap U.S. companies, 18 percent in U.S. Government securities, 9 percent in corporate bonds, 6 percent in cash equivalents and 17 percent in other investments.

	Fair Value Measurements at December 31, 2018, 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, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 4,930	$ —	$ 4,930
Equity securities:				
U.S. companies	11,038	—	—	11,038
International companies	—	967	—	967
Collective and mutual funds*	145,960	51,600	—	197,560
Corporate bonds	—	73,110	—	73,110
Municipal bonds	—	10,624	—	10,624
U.S. Government securities	479	5,896	—	6,375
Total assets measured at fair value	$ 157,477	$ 147,127	$ —	$ 304,604

* Collective and mutual funds invest approximately 27 percent in common stock of international companies, 31 percent in corporate bonds, 18 percent in common stock of large-cap U.S. companies, 5 percent in cash equivalents and 19 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, 2019 and 2018, 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, 2019, 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, 2019
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 4,017	$ —	$ 4,017
Equity securities:				
U.S. companies	2,073	—	—	2,073
International companies	—	1	—	1
Insurance contract*	10	88,486	—	88,496
Total assets measured at fair value	$ 2,083	$ 92,504	$ —	$ 94,587

* The insurance contract invests approximately 50 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 11 percent in other investments.

	Fair Value Measurements at December 31, 2018, 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, 2018
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 3,866	$ —	$ 3,866
Equity securities:				
U.S. companies	1,767	—	—	1,767
International companies	—	2	—	2
Insurance contract*	1	76,880	—	76,881
Total assets measured at fair value	$ 1,768	$ 80,748	$ —	$ 82,516

* The insurance contract invests approximately 51 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 12 percent in other investments.

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified defined 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 projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2019	2018
	(In thousands)	
Projected benefit obligation	$ 99,245	$ 93,988
Accumulated benefit obligation	$ 99,245	$ 93,988

Components of net periodic benefit cost for these plans for the years ended December 31 were as follows:

	2019	2018	2017
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	$ 109	$ 185	$ 289
Interest cost	3,473	3,157	3,494
Recognized net actuarial loss	764	1,047	883
Net periodic benefit cost	$ 4,346	$ 4,389	$ 4,666

Weighted average assumptions used at December 31 were as follows:

	2019	2018
Benefit obligation discount rate	2.73%	3.86%
Benefit obligation rate of compensation increase	N/A	N/A
Net periodic benefit cost discount rate	3.86%	3.20%
Net periodic benefit cost rate of compensation increase	N/A	N/A

The amount of future benefit payments for the unfunded, nonqualified defined benefit plans at December 31, 2019, are expected to aggregate as follows:

	2020	2021	2022	2023	2024	2025-2029
			(In thousands)			
Nonqualified benefits	$ 7,774	$ 7,795	$ 7,023	$ 7,219	$ 7,597	$ 35,998

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2019, 2018 and 2017 were $1.6 million, $597,000 and $736,000, respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

	2019	2018
	(In thousands)	
Investments		
Insurance contract*	$ 87,009	$ 73,838
Life insurance**	38,659	37,274
Other	8,450	10,818
Total investments	$ 134,118	$ 121,930

* For more information on the insurance contract, see Note 8.
** Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $51.8 million in 2019, $42.4 million in 2018 and $41.2 million in 2017.

Multiemployer plans

The Company contributes to a number of MEPPs under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its MEPPs, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2019 and 2018 is for the plan's year-end at December 31, 2018, and December 31, 2017, 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 2019	Pension Protection Act Zone Status 2018	FIP/RP Status Pending/ Implemented	Contributions 2019	Contributions 2018	Contributions 2017	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Alaska Laborers-Employers Retirement Fund	91-6028298-001	**Yellow as of 6/30/2019**	Yellow as of 6/30/2018	Implemented	**$ 815**	$ 732	$ 690	No	12/31/2020
Construction Industry and Laborers Joint Pension Trust for So Nevada, Plan A	88-0135695-001	**Red**	Red	Implemented	**544**	346	377	No	6/30/2020
Edison Pension Plan	93-6061681-001	**Green**	Green	No	**12,252**	12,111	12,725	No	12/31/2020
IBEW Local 212 Pension Trust	31-6127280-001	**Green as of 4/30/2019**	Green as of 4/30/2018	No	**1,110**	1,341	1,312	No	6/1/2025
IBEW Local 357 Pension Plan A	88-6023284-001	**Green**	Green	No	**10,162**	3,460	3,286	No	5/31/2021
IBEW Local 648 Pension Plan	31-6134845-001	**Yellow as of 2/28/2019**	Yellow as of 2/28/2018	Implemented	**728**	2,175	2,254	No	8/29/2021
IBEW Local 82 Pension Plan	31-6127268-001	**Green as of 6/30/2019**	Green as of 6/30/2018	No	**1,662**	1,569	1,757	No	12/3/2023
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	**Green as of 5/31/2019**	Green as of 5/31/2018	No	**1,307**	1,247	1,156	No	3/31/2023
Minnesota Teamsters Construction Division Pension Fund	41-6187751-001	**Green as of 11/30/2018**	Green as of 11/30/2017	No	**673**	740	826	No	4/30/2021
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	**Red**	Red	Implemented	**1,074**	738	718	No	3/31/2021-7/31/2024
National Electrical Benefit Fund	53-0181657-001	**Green**	Green	No	**12,679**	8,468	8,891	No	8/31/2019-6/1/2025 *
Pension Trust Fund for Operating Engineers	94-6090764-001	**Yellow**	Yellow	Implemented	**2,598**	2,403	2,391	No	3/31/2020-6/15/2022
Sheet Metal Workers Pension Plan of Southern CA, AZ, and NV	95-6052257-001	**Yellow**	Yellow	Implemented	**2,119**	1,774	1,016	No	6/30/2020
Southwest Marine Pension Trust	95-6123404-001	**Red**	Red	Implemented	**132**	81	48	No	1/31/2024
Other funds					**24,670**	21,537	19,298		
Total contributions					**$ 72,525**	$ 58,722	$ 56,745		

* Plan includes contributions required by collective bargaining agreements which have expired, but contain provisions automatically renewing their terms in the absence of a subsequent negotiated agreement.

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	2018 and 2017
IBEW Local 82 Pension Plan	2018 and 2017
IBEW Local 124 Pension Trust Fund	2018 and 2017
IBEW Local 212 Pension Trust Fund	2018 and 2017
IBEW Local 357 Pension Plan A	2018 and 2017
IBEW Local 648 Pension Plan	2018 and 2017
IBEW Local Union No 226 Open End Pension Fund	2018
Idaho Plumbers and Pipefitters Pension Plan	2018 and 2017
International Union of Operating Engineers Local 701 Pension Trust Fund	2018 and 2017
Minnesota Teamsters Construction Division Pension Fund	2018 and 2017
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2018 and 2017

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $59.5 million, $51.9 million and $50.8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Amounts contributed in 2019, 2018 and 2017 to defined contribution multiemployer plans were $49.2 million, $31.1 million and $32.2 million, respectively.

Note 18 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in three coal-fired electric generating facilities (Big Stone Station, Coyote Station and Wygen III) and one major transmission line (BSSE). Each owner of the jointly owned facilities is responsible for financing its investment.

The Company's share of the jointly owned facilities operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power; 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, construction work in progress and related accumulated depreciation for the jointly owned facilities was as follows:

	Ownership Percentage	2019	2018
		(In thousands)	
Big Stone Station:	22.7%		
Utility plant in service		**$ 152,836**	$ 156,534
Construction work in progress		**518**	92
Less accumulated depreciation		**46,266**	49,345
		$ 107,088	$ 107,281
BSSE:	50.0%		
Utility plant in service		**$ 105,767**	$ —
Construction work in progress		**—**	105,846
Less accumulated depreciation		**1,232**	—
		$ 104,535	$ 105,846
Coyote Station:	25.0%		
Utility plant in service		**$ 160,235**	$ 155,236
Construction work in progress		**21**	1,920
Less accumulated depreciation		**107,638**	105,565
		$ 52,618	$ 51,591
Wygen III:	25.0%		
Utility plant in service		**$ 67,869**	$ 65,382
Construction work in progress		**112**	220
Less accumulated depreciation		**10,482**	9,174
		$ 57,499	$ 56,428

Note 19 - 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. As indicated below, certain regulatory proceedings and cases may also contain recurring mechanisms that can have an annual true-up. Examples of these recurring mechanisms include: infrastructure riders, transmission trackers, renewable resource cost adjustment riders, as well as weather normalization and decoupling mechanisms. The following paragraphs summarizes the Company's significant regulatory proceedings and cases by jurisdiction including the status of each open request. The Company is unable to predict the ultimate outcome of these matters, the timing of final decisions of the various regulators and courts, or the effect on the Company's results of operations, financial position or cash flows.

MNPUC

On September 27, 2019, Great Plains filed an application with the MNPUC for a natural gas rate increase of approximately $2.9 million annually or approximately 12.0 percent above current rates. The requested increase was primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. On November 22, 2019, Great Plains received approval to implement an interim rate increase of approximately $2.6 million or approximately 11.0 percent, subject to refund, effective January 1, 2020. This matter is pending before the MNPUC.

MTPSC

On November 1, 2019, Montana-Dakota submitted an application with the MTPSC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. This matter is pending before the MTPSC.

NDPSC

Montana-Dakota has a transmission cost adjustment rider that allows annual updates to rates for actual costs for transmission-related projects and services. On July 19, 2019, Montana-Dakota filed a change to its transmission cost adjustment rates to reflect projected charges for July 2019 through June 2020 assessed to Montana-Dakota for transmission-related services provided by MISO and Southwest Power Pool, along with the projected transmission service revenues or credits received for the same time period. Montana-Dakota also requested recovery of six transmission capital projects. Total revenues of approximately $9.2 million, which reflects a true-up of the prior period adjustment, were requested resulting in an increase of approximately $600,000 or approximately 7.2 percent over current rates, which includes approximately $1.5 million related to transmission capital projects. On October 22, 2019, the NDPSC approved the rates as requested. The rates were effective October 28, 2019.

Montana-Dakota has a renewable resource cost adjustment rate tariff that allows for annual adjustments for recent projected capital costs and related expenses for projects determined to be recoverable under the tariff. On November 1, 2019, Montana-Dakota filed an annual update to its renewable resource cost adjustment requesting to recover a revised revenue requirement of approximately $14.7 million annually, not including the prior period true-up adjustment. The update reflects a decrease of approximately $800,000 from the revenues currently included in rates. On February 19, 2020, the NDPSC approved the increase with rates effective on March 1, 2020.

On August 28, 2019, Montana-Dakota filed an application with the NDPSC for an advanced determination of prudence and a certificate of public convenience and necessity to construct, own and operate Heskett Unit 4, an 88-MW simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station near Mandan, North Dakota. This matter is pending before the NDPSC.

On September 16, 2019, Montana-Dakota submitted an application with the NDPSC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. This matter is pending before the NDPSC.

OPUC

On December 29, 2017, Cascade filed a request with the OPUC to use deferred accounting for the 2018 net benefits associated with the implementation of the TCJA. On September 12, 2019, the OPUC approved the request, including a settlement to refund to customers approximately $1.4 million related to TJCA impacts for the period from January 2018 through March 2019. These refunds will be reflected in customers' rates over a 12-month period beginning November 1, 2019.

On June 14, 2019, Cascade filed a request with the OPUC to implement a new pipeline safety cost recovery mechanism to recover investments to replace Cascade's highest risk infrastructure which would have required Cascade to file a report annually with the OPUC detailing actual projects undertaken and the related costs incurred. This matter was denied by the OPUC on January 15, 2020.

SDPUC

On November 8, 2019, Montana-Dakota submitted an application with the SDPUC requesting the use of deferred accounting for the treatment of costs related to the retirement of Lewis & Clark Station in Sidney, Montana, and units 1 and 2 at Heskett Station near Mandan, North Dakota. The SDPUC approved the use of deferred accounting treatment as requested on January 7, 2020.

WUTC

On March 29, 2019, Cascade filed a natural gas general rate case with the WUTC requesting an increase in annual revenue of $12.7 million or approximately 5.5 percent. On September 20, 2019, Cascade filed a joint settlement agreement with the WUTC reflecting a revised annual increase of approximately $6.5 million or approximately 2.8 percent with an effective date of March 1, 2020. A settlement hearing was held on November 5, 2019. On February 3, 2020, the WUTC approved the increase with rates effective on March 1, 2020.

Cascade has a pipeline replacement cost recovery mechanism, which is designed to recover the replacement cost of the Company's most at risk pipelines. The mechanism requires an annual filing on May 31, as well as two update filings for actual costs before the November 1 effective date. On May 31, 2019, Cascade filed its seventh annual update to its pipeline cost recovery mechanism requesting an increase in revenue of approximately $1.6 million or approximately 0.7 percent. On October 10, 2019, Cascade filed a final update to the cost recovery mechanism with a revised increase in revenue of approximately $440,000 or approximately 0.2 percent annually. On October 24, 2019, the WUTC approved the increase with rates effective for services provided on or after November 1, 2019.

Cascade defers the actual cost of gas spent to serve customers and annually records a true-up to their purchased gas adjustment tariff. On September 13, 2019, Cascade filed its annual update to its purchased gas adjustment with the WUTC requesting an annual increase of approximately $12.8 million or approximately 5.7 percent for a period of three years. The requested increase is primarily due to unrecovered purchased gas costs as a result of the rupture of the Enbridge pipeline in Canada on October 9, 2018, causing increased natural gas costs. On October 24, 2019, the WUTC approved the increase with rates effective for services provided on or after November 1, 2019.

WYPSC

On May 23, 2019, Montana-Dakota filed an application with the WYPSC for a natural gas rate increase of approximately $1.1 million annually or approximately 7.0 percent above current rates. The requested increase was to recover increased operating expenses and investments in distribution facilities to improve system safety and reliability. On December 17, 2019, Montana-Dakota filed a settlement agreement with the WYPSC reflecting an annual increase in revenues of approximately $830,000 or approximately 5.5 percent with rates effective March 1, 2020. This matter is pending before the WYPSC.

FERC

On December 9, 2019, MISO accepted Montana-Dakota's annual revenue requirement update to its transmission formula rates under the MISO tariff for its multi-value project for approximately $13.1 million, which was effective January 1, 2020. The update effective January 1, 2020, reflects the reduced return on equity order issued by the FERC on November 21, 2019.

Note 20 - 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.

At December 31, 2019 and 2018, the Company accrued liabilities which have not been discounted, including liabilities held for sale, of $29.1 million and $30.4 million, respectively. The accruals are for contingencies, including litigation, production taxes, royalty claims and environmental matters. This includes amounts that have been accrued for matters discussed in 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.

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 the riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. along the Willamette River. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site where the EPA wants responsible parties to share in the costs of cleanup. 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. Investigative costs are indicated to be in excess of $100 million. Remediation 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 was also notified 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. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

At this time, Knife River - Northwest does not believe it is a responsible party and 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. LWG has 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 Sites Claims have been made against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors and a similar claim has been made against Montana-Dakota for a site operated by Montana-Dakota and its predecessors. Any accruals related to these claims are reflected in regulatory assets. For more information, see Note 7.

Demand has been made of Montana-Dakota to participate in investigation and remediation of environmental contamination at a site in Missoula, Montana. The site operated as a former manufactured gas plant from approximately 1907 to 1938 when it was converted to a butane-air plant that operated until 1956. Montana-Dakota or its predecessors owned or controlled the site for a period of the time it operated as a manufactured gas plant and Montana-Dakota operated the butane-air plant from 1940 to 1951, at which time it sold the plant. There are no documented wastes or by-products resulting from the mixing or distribution of butane-air gas. Preliminary assessment of a portion of the site provided a recommended remedial alternative for that portion of approximately $560,000. However, the recommended remediation would not address any potential contamination to adjacent parcels that may be impacted by contamination from the manufactured gas plant. Montana-Dakota and another party agreed to voluntarily investigate and remediate the site and that Montana-Dakota will pay two-thirds of the costs for further investigation and remediation of the site. Montana-Dakota received notice from a prior insurance carrier that it will participate in payment of defense costs incurred in relation to the claim. Montana-Dakota has accrued $375,000 for the remediation of this site.

A claim was made against Cascade 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 $4.4 million has been incurred. Cascade has accrued $3.2 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 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.

A claim was made against Cascade 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. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared for one of the PRPs in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. The other PRPs will develop a cleanup action plan and, after public review of the cleanup action plan, develop design documents. 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, the plant converted 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 recorded an accrual for this site for an amount that is not material.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for certain of the contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade intends to seek recovery of remediation costs through the OPUC and WUTC in its natural gas rates charged to customers.

Purchase commitments

The Company has entered into various commitments largely consisting of contracts for natural gas and coal supply; purchased power; natural gas transportation and storage; employee service; information technology; and construction materials. Certain of these contracts are subject to variability in volume and price. The commitment terms vary in length, up to 41 years. The commitments under these contracts as of December 31, 2019, were:

	2020	2021	2022	2023	2024	Thereafter
			(In thousands)			
Purchase commitments	$ 405,535	$ 250,266	$ 184,225	$ 123,166	$ 87,297	$ 678,432

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2019, 2018 and 2017, were $686.5 million, $548.0 million and $516.1 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 were expected to mature in 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining. On October 17, 2018, Centennial was released from this guarantee of certain debt obligations of Dakota Prairie Refining.

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 agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries. The remaining guarantee is expected to expire in 2021. 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, 2019, the fixed maximum amounts guaranteed under these agreements aggregated $174.8 million. Certain of the guarantees also have no fixed maximum amounts specified. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate to $162.6 million in 2020; $700,000 in 2021; $400,000 in 2022; $500,000 in 2023; $500,000 in 2024; $1.1 million thereafter; and $9.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2019. 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, 2019, the fixed maximum amounts guaranteed under these letters of credit aggregated $33.2 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate to $32.7 million in 2020 and $500,000 in 2021. There were no amounts outstanding under the above letters of credit at December 31, 2019. In the event of default under these letter of credit obligations, the subsidiary guaranteeing the letter of credit would be obligated for reimbursement of payments made under the 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 or MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company were reflected on the Consolidated Balance Sheet at December 31, 2019.

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. At December 31, 2019, approximately $1.1 billion of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary.

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 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, 2019, 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 $36.0 million.

Note 21 - Subsequent Events

On February 3, 2020, the Company acquired PerLectric, Inc., a leading electrical construction company in Fairfax, Virginia, which will be included in the Company's construction services segment. On February 14, 2020, the Company acquired the assets of Oldcastle Infrastructure Spokane, a prestressed-concrete business located in Spokane, Washington, which will be included in the Company's construction materials and contracting segment. To date, the initial accounting for these acquisitions is incomplete. Due to the limited time since the date of these acquisitions, it is impracticable for the Company to make business combination disclosures related to these acquisitions. The Company is still gathering the necessary information to provide such disclosures in future filings.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2019 and 2018:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2019				
Operating revenues	**$ 1,091,191**	**$ 1,303,573**	**$ 1,563,799**	**$ 1,378,213**
Operating expenses	**1,026,973**	**1,206,262**	**1,374,329**	**1,247,992**
Operating income	**64,218**	**97,311**	**189,470**	**130,221**
Income from continuing operations	**41,089**	**63,145**	**136,128**	**94,804**
Income (loss) from discontinued operations, net of tax	**(163)**	**(1,320)**	**1,509**	**261**
Net income	**40,926**	**61,825**	**137,637**	**95,065**
Earnings per share - basic:				
Income from continuing operations	**.21**	**.32**	**.68**	**.47**
Discontinued operations, net of tax	**—**	**(.01)**	**.01**	**—**
Earnings per share - basic	**.21**	**.31**	**.69**	**.47**
Earnings per share - diluted:				
Income from continuing operations	**.21**	**.32**	**.68**	**.47**
Discontinued operations, net of tax	**—**	**(.01)**	**.01**	**—**
Earnings per share - diluted	**.21**	**.31**	**.69**	**.47**
Weighted average common shares outstanding:				
Basic	**196,401**	**198,270**	**199,343**	**200,383**
Diluted	**196,414**	**198,287**	**199,383**	**200,478**
2018				
Operating revenues	$ 976,293	$ 1,064,597	$ 1,280,787	$ 1,209,875
Operating expenses	906,917	990,605	1,140,783	1,091,524
Operating income	69,376	73,992	140,004	118,351
Income from continuing operations	41,960	44,075	107,369	75,982
Income (loss) from discontinued operations, net of tax	477	(273)	(118)	2,846
Net income	42,437	43,802	107,251	78,828
Earnings per share - basic:				
Income from continuing operations	.22	.22	.55	.39
Discontinued operations, net of tax	—	—	—	.01
Earnings per share - basic	.22	.22	.55	.40
Earnings per share - diluted:				
Income from continuing operations	.22	.22	.55	.39
Discontinued operations, net of tax	—	—	—	.01
Earnings per share - diluted	.22	.22	.55	.40
Weighted average common shares outstanding:				
Basic	195,304	195,524	196,018	196,023
Diluted	195,982	196,169	196,265	196,385

Certain operations of the Company 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.

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota (50 percent ownership)
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
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet Specialty Products Partners, L.P. (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 prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana–Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.

MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
PRP	Potentially Responsible Party
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
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 Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

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

None.

Item 9A. Controls and Procedures

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

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the three months ended December 31, 2019, 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 will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be 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, 2019, 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)	596,341	(2)	$ —	(3)	4,012,055	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	
Total	596,341		$ —		4,012,055	

(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 and restricted stock awards.
(3) No weighted average exercise price is shown for the performance shares or restricted stock awards because such awards have no exercise price.
(4) This amount includes 3,737,848 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 274,207 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan.

The remaining information required by this item will be 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 will be 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 will be 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.

2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report.

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	2019	2018	2017
		(In thousands)	
Operating revenues	$ —	$ 628,331	$ 623,693
Operating expenses	—	540,125	520,069
Operating income	—	88,206	103,624
Other income	—	1,504	4,876
Interest expense	—	32,761	31,997
Income before income taxes	—	56,949	76,503
Income taxes	—	(4,259)	13,800
Equity in earnings of subsidiaries from continuing operations	335,166	208,177	222,283
Net income from continuing operations	335,166	269,385	284,986
Equity in earnings (loss) of subsidiaries from discontinued operations	287	2,933	(3,783)
Loss on redemption of preferred stock	—	—	600
Dividends declared on preferred stock	—	—	171
Earnings on common stock	$ 335,453	$ 272,318	$ 280,432
Comprehensive income	$ 331,693	$ 279,269	$ 279,602

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,	2019	2018
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 12,326	$ 2,271
Receivables, net	4,727	92,724
Accounts receivable from subsidiaries	49,943	36,015
Inventories	—	13,293
Prepayments and other current assets	501	14,488
Total current assets	67,497	158,791
Investments	46,294	76,202
Investment in subsidiaries	2,842,068	1,790,886
Property, plant and equipment	—	2,846,715
Less accumulated depreciation, depletion and amortization	—	836,735
Net property, plant and equipment	—	2,009,980
Deferred charges and other assets:		
Goodwill	—	4,812
Operating lease right-of-use assets	153	—
Other	34,367	180,473
Total deferred charges and other assets	34,520	185,285
Total assets	$ 2,990,379	$ 4,221,144
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ —	$ 200,711
Accounts payable	2,981	50,051
Accounts payable to subsidiaries	4,752	12,438
Taxes payable	1,253	24,704
Dividends payable	41,580	39,695
Accrued compensation	8,812	14,346
Current operating lease liabilities	96	—
Other accrued liabilities	7,690	54,099
Total current liabilities	67,164	396,044
Long-term debt	—	586,012
Deferred credits and other liabilities:		
Deferred income taxes	—	165,122
Noncurrent operating lease liabilities	56	—
Other	75,913	507,191
Total deferred credits and other liabilities	75,969	672,313
Commitments and contingencies		
Stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Shares issued - 200,922,790 at December 31, 2019 and 196,564,907 at December 31, 2018	200,923	196,565
Other paid-in capital	1,355,404	1,248,576
Retained earnings	1,336,647	1,163,602
Accumulated other comprehensive loss	(42,102)	(38,342)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total stockholders' equity	2,847,246	2,566,775
Total liabilities and stockholders' equity	$ 2,990,379	$ 4,221,144

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2019	2018	2017
		(In thousands)	
Net cash provided by operating activities	$ 168,520	$ 294,379	$ 284,075
Investing activities:			
Capital expenditures	—	(242,692)	(146,370)
Net proceeds from sale or disposition of property and other	—	5,032	(5,665)
Investments in and advances to subsidiaries	(120,000)	(40,000)	(40,000)
Advances from subsidiaries	17,000	70,000	40,000
Investments	(236)	(528)	(468)
Net cash used in investing activities	(103,236)	(208,188)	(152,503)
Financing activities:			
Issuance of long-term debt	—	199,422	70,080
Repayment of long-term debt	—	(125,961)	(37,569)
Payments of stock issuance costs	—	(10)	—
Proceeds from issuance of common stock	106,848	—	—
Dividends paid	(160,256)	(154,573)	(150,727)
Redemption of preferred stock	—	—	(15,600)
Repurchase of common stock	—	(1,920)	(564)
Tax withholding on stock-based compensation	(1,821)	(1,721)	(508)
Net cash used in financing activities	(55,229)	(84,763)	(134,888)
Increase (decrease) in cash and cash equivalents	10,055	1,428	(3,316)
Cash and cash equivalents - beginning of year	2,271	843	4,159
Cash and cash equivalents - end of year	$ 12,326	$ 2,271	$ 843

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, MDU Resources Group, Inc. (the Company) as of and for the year ended December 31, 2019. Prior to the Holding Company Reorganization, the Company included Montana-Dakota and Great Plains, public utility divisions of the Company as of December 31, 2018. On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. Immediately after consummation, the Company had, on a consolidated basis, the same assets, businesses and operations as it had immediately prior to the reorganization. For more information on the reorganization, see Item 8 - Note 1. The prior periods have not been restated and reflect the condensed financial information of Montana-Dakota and Great Plains as of and for the years ended December 31, 2018 and 2017. Due to the completion of the Holding Company Reorganization, the presentation of prior periods will vary from that of and for the year ended December 31, 2019. 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 material cash inflows on the Condensed Statements of Cash Flows are primarily from the dividends and other payments received from its subsidiaries and the proceeds raised from the issuance of equity securities. 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 per common share Please refer to the Consolidated Statements of Income of the registrant for earnings per common share. In addition, see Item 8 - Note 1 for information on the computation of earnings per common share.

Note 2 - Debt At December 31, 2019, the Company had no long-term debt maturities. For more information on debt, see Item 8 - Note 9.

Note 3 - Dividends The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $177.1 million, $115.9 million and $116.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.

MDU RESOURCES GROUP, INC.

Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2019, 2018 and 2017

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2019	**$ 8,850**	**$ 7,864**	**$ 980**	**$ 9,197**	**$ 8,497**
2018	8,069	7,532	1,121	7,872	8,850
2017	10,479	7,024	989	10,423	8,069

* 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.

3. Exhibits

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference: Form	Period Ended	Exhibit	Filing Date	File Number
2(a)	Agreement and Plan of Merger, dated December 31, 2018, by and among MDU Resources Group, Inc., MDUR Newco, Inc. MDU Newco Sub, Inc.		8-K		2(a)	1/2/19	1-03480
3(a)	Amended and Restated Certificate of Incorporation of MDU Resources Group, Inc.		8-K		3.2	5/8/19	1-03480
3(b)	Amended and Restated Bylaws of MDU Resources Group, Inc.		8-K		3.1	2/15/19	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)	Fifth Amended and Restated Credit Agreement, dated as of December 19, 2019, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto	X					
*4(d)	Montana-Dakota Utilities Co. Amended and Restated Credit Agreement, dated December 19, 2019, among Montana-Dakota Utilities Co., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent	X					
4(e)	Centennial Energy Holdings, Inc. Note Purchase Agreement, dated December 20, 2012, among Centennial Energy Holdings, Inc. and various purchasers of the notes		10-Q	6/30/19	4(a)	8/2/19	1-03480
4(f)	Montana-Dakota Utilities Co. Note Purchase Agreement, dated July 24, 2019, among Montana-Dakota Utilities Co. and various purchasers of the notes		10-Q	9/30/19	4(a)	11/1/19	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
4(g)	MDU Resources Group, Inc. Description of Securities Registered Pursuant to Section 12 of the Securities and Exchange Act of 1934	X					
+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 8, 2019		10-Q	6/30/19	10(a)	8/2/19	1-03480
+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 November 13, 2019, and Rules and Regulations, as amended November 13, 2019	X					
+10(h)	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(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 15, 2018		8-K		10.1	2/21/18	1-03480
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2019		10-K	12/31/18	10(k)	2/22/19	1-03480
+10(k)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 13, 2020	X					
+10(l)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 15, 2018		8-K		10.3	2/21/18	1-03480
+10(m)	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(n)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	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)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated April 25, 2018		10-Q	6/30/19	10(b)	8/2/19	1-03480
+10(u)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 6, 2018		10-Q	6/30/19	10(c)	8/2/19	1-03480
+10(v)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 20, 2018		10-Q	6/30/19	10(d)	8/2/19	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
+10(w)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 22, 2019		10-Q	6/30/19	10(e)	8/2/19	1-03480
+10(x)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 22, 2019		10-Q	9/30/19	10(a)	11/1/19	1-03480
+10(y)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated October 15, 2019	X					
+10(z)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(aa)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
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					
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						

* Schedules and exhibits to this agreement have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished as a supplement to the SEC upon request.

+ 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 21, 2020 By: /s/ David L. Goodin

David L. Goodin
(President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the date indicated.

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 21, 2020
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Financial Officer and Treasurer)	Chief Financial Officer	February 21, 2020
/s/ Stephanie A. Barth Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 21, 2020
/s/ Dennis W. Johnson Dennis W. Johnson (Chair of the Board)	Director	February 21, 2020
/s/ Thomas Everist Thomas Everist	Director	February 21, 2020
/s/ Karen B. Fagg Karen B. Fagg	Director	February 21, 2020
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 21, 2020
/s/ Patricia L. Moss Patricia L. Moss	Director	February 21, 2020
/s/ Edward A. Ryan Edward A. Ryan	Director	February 21, 2020
/s/ David M. Sparby David M. Sparby	Director	February 21, 2020
/s/ Chenxi Wang Chenxi Wang	Director	February 21, 2020
/s/ John K. Wilson John K. Wilson	Director	February 21, 2020

MDU RESOURCES
GROUP, INC.

David L. Goodin
President and
Chief Executive Officer

1200 W. Century Ave.
Bismarck, ND 58503
Mailing address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000
www.MDU.com

March 27, 2020

Fellow Stockholders:

I invite you to join me, our Board of Directors and members of our senior management team for our annual meeting at 11 a.m. on May 12, 2020, at 909 Airport Road in Bismarck, North Dakota.

We will hear at the meeting the results of stockholder voting on the items outlined in this Proxy Statement, including election of our Board of Directors, advisory vote to approve the compensation paid to our named executive officers, and ratification of the appointment of our independent auditors.

In addition to the business items to be conducted at the annual meeting, I will provide an overview of our excellent 2019 financial results and the growth we accomplished during the year. We have a strong outlook for 2020, and I will provide additional details about our backlog of construction work as well as the growth projects underway at our regulated energy delivery businesses.

As you read this year's Proxy Statement, you will find information about the board's newly chartered Environmental and Sustainability Committee. This committee helps the board fulfill its oversight responsibilities related to MDU Resources' environmental, workplace health, safety and other social sustainability matters. We also adapted our corporate environmental, social and governance reporting in 2019 to follow standards outlined by the Sustainability Accounting Standards Board and industry organizations. You can find this ESG information on our website at www.mdu.com/sustainability. Our board is committed to continuing to expand efforts regarding ESG matters.

I look forward to seeing you May 12 at the annual stockholder meeting. You can find information on p. 67 of this Proxy Statement about how to receive an admission ticket to the meeting.

If you cannot attend, your vote is still important to us. I ask that you please promptly follow the instructions on your notice or proxy card to vote your shares.

We appreciate your continued investment in MDU Resources and remain committed to providing you with the long-term returns you expect.

Sincerely,

David L. Goodin
President and Chief Executive Officer

MDU RESOURCES GROUP, INC.

1200 West Century Avenue

Mailing Address:
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(701) 530-1000

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS TO BE HELD MAY 12, 2020

March 27, 2020

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 58504, on Tuesday, May 12, 2020, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

Items of Business	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 2020; 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 13, 2020, as the record date for the determination of stockholders who will be entitled to notice of, and to vote at, the meeting and any adjournment(s) thereof.
Meeting Attendance	All stockholders as of the record date of March 13, 2020, are cordially invited and urged to attend the annual meeting. You must request an admission ticket 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. 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 13, 2020, 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, 2020. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.
Proxy Materials	Notice of Availability of Proxy Materials will be first sent to stockholders on or about March 27, 2020. 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 April 2, 2020.

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 12, 2020. The 2020 Notice of Annual Meeting and Proxy Statement and 2019 Annual Report to Stockholders are available at www.mdu.com/proxymaterials.

TABLE OF CONTENTS

PROXY STATEMENT SUMMARY

To assist you in reviewing the company's 2019 performance and voting your shares, we call your attention to key elements of our 2020 Proxy Statement. The following is only a summary and does not contain all the information you should consider. You should read the entire Proxy Statement carefully before voting. For more information about these topics, please review the full Proxy Statement and our 2019 Annual Report to Stockholders.

Meeting Information

Time and Date
11:00 a.m. Central Daylight Saving Time Tuesday, May 12, 2020
Place
MDU Service Center 909 Airport Road Bismarck, ND 58504

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	31
Item 3.	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2020	FOR	62

Corporate Governance Practices

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 Board 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
- ✓ "Proxy Access" Allowing Stockholders to Nominate Directors in Accordance With the Terms of Our Bylaws

- ✓ Standing Committees Consist Entirely of Independent Directors
- ✓ Active Investor Outreach Program
- ✓ Stock Ownership Requirements for Directors and Executive Officers
- ✓ Anti-Hedging and Anti-Pledging Policies for Directors and Executive Officers
- ✓ No Related Party Transactions by Our Directors or Executive Officers
- ✓ Compensation Recovery/Clawback Policy
- ✓ Annual Advisory Approval on Executive Compensation
- ✓ Mandatory Retirement for Directors at Age 76
- ✓ Directors May Not Serve on More Than Three Public Boards Including the Company's Board

Governance Highlights

We are committed to strong corporate governance aligned with stockholder interests. The board, through its nominating and governance committee, regularly monitors leading practices in governance and adopts measures that it determines are in the best interests of the company and its stockholders.

- Three new independent directors were added to the board during 2018 and 2019 with the retirement of three former directors, including the independent chair of the board.
- Dennis W. Johnson, who previously served as chair of our audit committee, was elected as the new independent board chair in 2019.
- The environmental and sustainability committee was established in 2019 as a standing committee of the board of directors to oversee environmental, workplace health, safety, and other social sustainability matters that fundamentally affect the company's business and long-term viability.
- In conjunction with the election of new directors, the appointment of Mr. Johnson as board chair, and the establishment of the environmental and sustainability committee, membership on the board's standing committees was refreshed with new chairs appointed for each of the committees.
- Membership of all committees consists entirely of independent directors.
- The company was recognized, for the third consecutive year, by the 2020 Women on Boards campaign for diversity on the corporation's board of directors.
- The company was recognized by the Women's Forum of New York as a 2019 Corporate Champion with at least 30% of board seats held by women.
- On January 1, 2019, we completed a holding company reorganization to provide additional financing flexibility and further separation between the company's utility and other business segments. As a result of the reorganization, all of the company's utility operations are conducted through wholly-owned subsidiaries.

Business Performance Highlights

Our overall performance in 2019 was consistent with our long-term strategy as we focused on growing our regulated energy delivery and construction materials and services business segments. In addition to our 2019 financial performance highlighted on the next page:

- The electric segment completed construction of the 345-kilovolt transmission line project from Ellendale, North Dakota, to Big Stone City, South Dakota, in February 2019.
- The electric segment announced plans to retire three aging coal-fired electric generation units at two locations within the next two to three years and construct a new simple-cycle natural gas combustion turbine. The retirement of the 44-megawatt Lewis & Clark Station in Sidney, Montana is expected in early 2021 and the Heskett units 1 and 2, which combine for 100 megawatts, would be retired in early 2022. Subject to regulatory approval, a new 88-megawatt simple-cycle peaking unit at the Heskett Station would be constructed in 2023.
- The construction materials and contracting segment had record revenues in 2019.
- The construction materials and contracting segment completed the acquisition of Viesko Redi-Mix, Inc. in Wheatland, Oregon in 2019.
- The construction materials and contracting segment also acquired aggregate reserves near Marble Falls, Texas in February 2019. In November 2019, the Texas Commission on Environmental Quality issued an Air Quality Standard Permit to construct a rock-crushing plant at the quarry. The quarry, which is expected to begin production in late 2020, contains an estimated 40-year supply of high quality aggregates enabling the construction materials and contracting segment to supply a significant portion of the base materials used for its local construction and production of ready-mixed concrete and asphalt along with third-party sales in our Texas market.
- The pipeline and midstream segment in 2019 had record transportation volumes for the third consecutive year. The segment completed construction of its Demicks Lake Project in McKenzie County, North Dakota, and Phase I of the Line Section 22 Project near Billings, Montana came online. The projects are designed to increase capacity by 175 MMcf and 14.3 MMcf per day, respectively. Construction on Phase II of the Line Section 22 Project, which includes additional design capacity of 8.2 MMcf per day, is expected to be completed the first half of 2020. In February 2020, the segment also completed construction and placed into service the Demicks Lake Expansion Project which is designed to increase capacity by 175 MMcf per day.
- The pipeline and midstream segment announced plans to construct approximately 62 miles of pipeline, compression, and ancillary facilities to transport natural gas from core Bakken production areas in western North Dakota to an interconnection point with another interstate transmission pipeline. This North Bakken Expansion Project, as designed, would provide 350 million cubic feet per day of natural gas transportation capacity with estimated completion in 2021.
- The construction services segment had record revenues in 2019.
- The construction services segment completed the acquisition of the assets of Pride Electric, Inc. in Redmond, Washington in 2019.

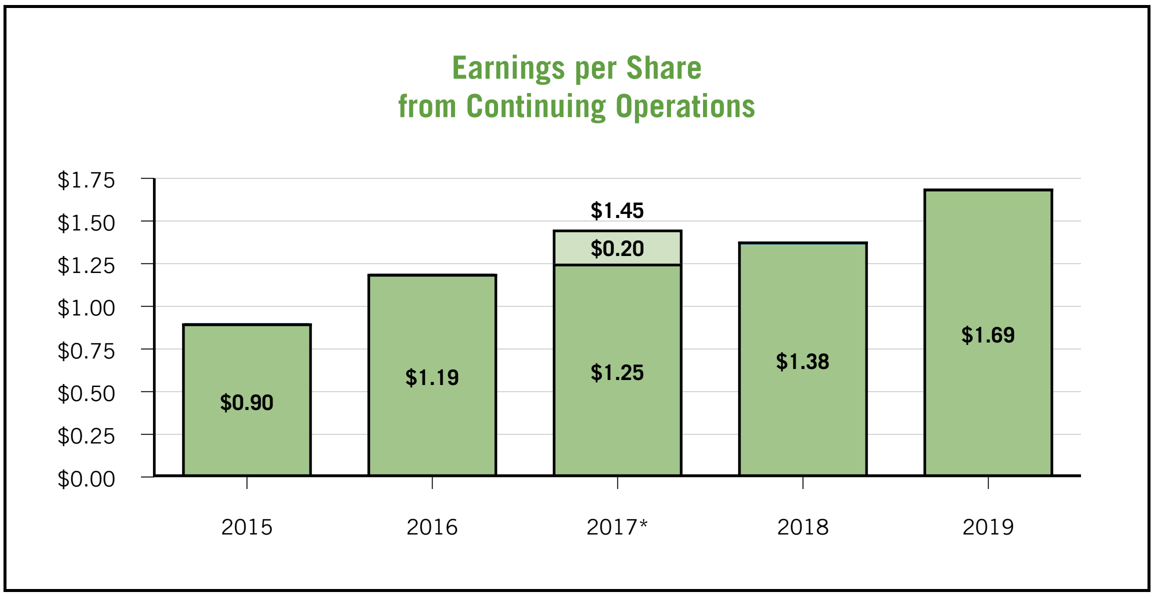
Performance from Continuing Operations

	2015	2016	2017	2018	2019
Electric Distribution Retail Sales (thousand kWh)	3,316,017	3,258,537	3,306,470	3,354,401	3,314,307
Natural Gas Distribution					
Retail Sales (Mdk)	95,559	99,296	112,551	112,566	123,675
Transportation (Mdk)	154,225	147,592	144,477	149,497	166,077
Pipeline Transportation (Mdk)	290,494	285,254	312,520	351,498	429,660
Construction Materials and Contracting Revenues (000's)	1,904,282	1,874,270	1,812,529	1,925,854	2,190,717
Construction Services Revenues (000's)	926,427	1,073,272	1,367,602	1,371,453	1,849,266

2019 Financial Performance Highlights

- Strong year-over-year performance from operations at both our regulated energy delivery and construction materials and services segments resulted in an earnings increase of 23% in 2019 to $335.5 million, or $1.69 per share, compared to 2018 earnings of $272.3 million, or $1.39 per share, including discontinued operations.

- Including our accomplishments in 2019, 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 non-recurring benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act that was signed into law on December 22, 2017.

- Returned $162.1 million to stockholders through dividends:
  - Increased dividend for 29th straight year to our current annualized dividend of 83 cents per share; and
  - Paid uninterrupted dividend for 82 straight years.
- Maintained BBB+ stable credit rating from Standard & Poor's and Fitch rating agencies.[1]
- Operating income increased 20 percent from $401.7 million in 2018 to $481.2 million in 2019.
- Over the five-year period, earnings per common share before discontinued operations have grown at 12% compounded annually.

[1] A securities rating is not a recommendation to buy, sell, or hold securities, and it may be revised or withdrawn at any time by the rating agency.

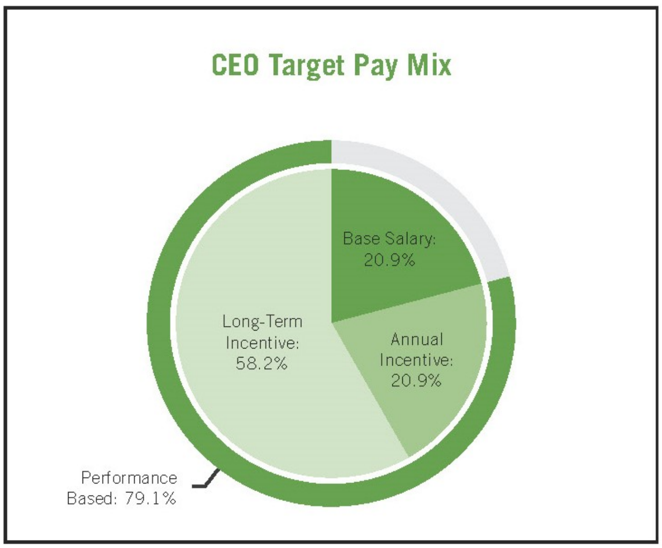
29 Years of Consecutive Dividend Increases	Dividends Paid $762 Million Over the Last 5 Years	82 Years of Uninterrupted Dividend Payments

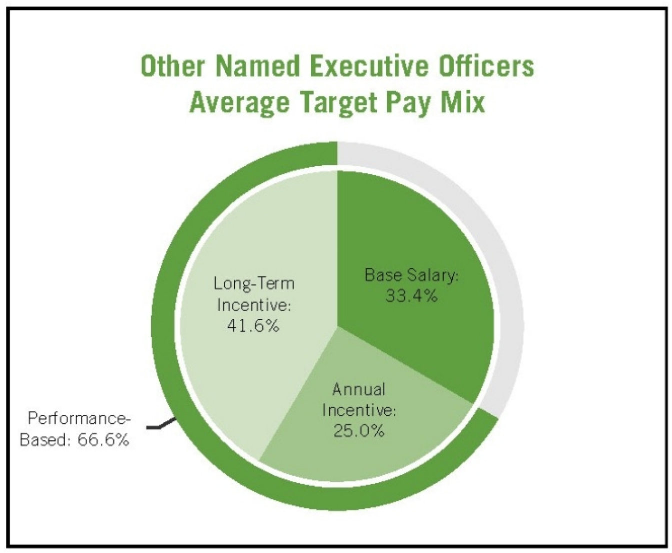
Compensation Highlights

The company's executive compensation is focused on paying for performance. Our compensation program is structured to align compensation with the company's financial performance as a substantial portion of our executive compensation is based upon performance incentive awards.

- Over 75% of our chief executive officer's target compensation and over 66% of our other 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 our executive officers to own a significant amount of company stock based upon a multiple of their base salary.

2019 Named Executive Officer Target Pay Mix





At the 2019 Annual Meeting, the company's advisory vote to approve executive compensation received support from over 96% of the common stock represented at the meeting and entitled to vote on the matter.

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 executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, business segment economic environment, and the actual performance of the overall company and the business segments.
- ☑ **Annual Cash Incentive** - Payment of annual cash incentive awards are based on business segment and overall company performance against pre-established annual financial measures.
- ☑ **Long-Term Equity Incentive** - Long-term incentive awards may be earned at the end of a three-year period based on achieving pre-established performance measures and are paid through performance shares which encourages stock ownership and helps retain management talent.
- ☑ **Balanced Mix of Pay Components** - The target compensation mix is not overly weighted toward annual incentive awards but rather represents a balance of annual cash and long-term equity-based compensation.
- ☑ **Mix of Financial Goals** - Use of a mixture of financial goals to measure performance prevents overemphasis on a single metric.
- ☑ **Annual Compensation Risk Analysis** - Risks related to our compensation programs are regularly analyzed through an annual compensation 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. Our president and chief executive officer is required to own stock equal to four times his base salary, and the other named executive officers are required to own stock equal to three times their base salary. The executive officers also must 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. Net performance shares must also be held until share ownership requirements have been met.
- ☑ **Clawback Policy** - If the company's audited financial statements are restated due to any material noncompliance with the financial reporting requirements under the securities laws, 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.

What We Do Not Do

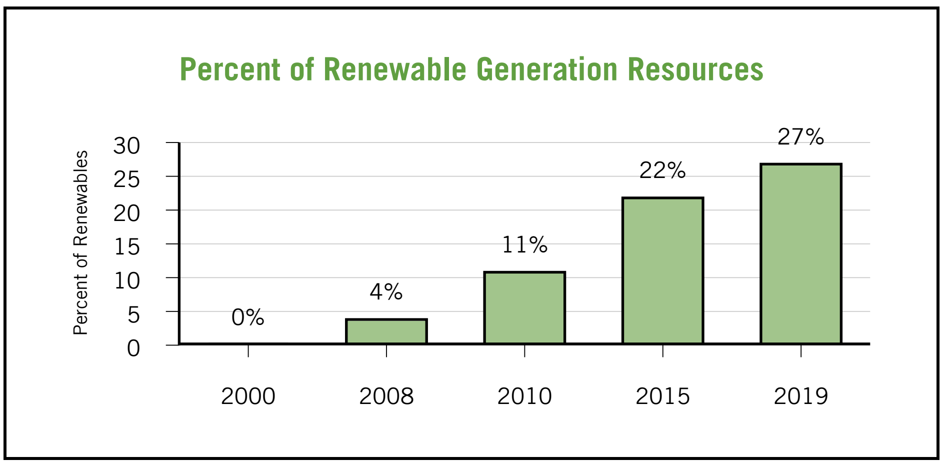
- ☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.
- ☒ **Employment Agreements** - Executives do not have employment agreements entitling them to specific payments upon termination or a change of control of the company.
- ☒ **Perquisites** - Executives do not receive perquisites that materially differ from those available to employees in general.
- ☒ **Hedge Stock** - Executives are not allowed to hedge company securities.
- ☒ **Pledge Stock** - Executives 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.
- ☒ **Tax Gross-Ups** - Executives do not receive tax gross-ups on their compensation except for circumstances regarding relocation.

Corporate Responsibility, Environmental, and Sustainability Highlights

MDU Resources Group, Inc. is Building a Strong America® by providing essential products and services to our customers with a long-term view toward sustainable operations. 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 environmental and sustainability practices and to maintaining the health and safety of the public and our employees. In 2019 the board of directors established the environmental and sustainability committee as a standing committee of the board. The committee meets quarterly in conjunction with the regular meetings of the board. The committee oversees and provides recommendations to management and the board regarding environmental, workplace health, safety, and other social sustainability matters that fundamentally affect the company's business interests and long-term liability. To better serve our investors and other stakeholders, in 2019 we began reporting environmental, social, governance, and sustainability (ESG/sustainability) metrics relevant and important to our operations in frameworks that provide our stakeholders more uniform and transparent data and information, allowing for comparison with our peers and other companies operating in our industries. For our electric and natural gas distribution segments, as well as our pipeline and midstream segment, we report ESG/sustainability metrics using the reporting templates developed by the Edison Electric Institute and the American Gas Association. For our other business segments, we report ESG/sustainability information under the framework developed by the Sustainability Accounting Standards Board (SASB) for our applicable industries. The use of the metrics developed by these organizations provides for ESG/sustainability reporting tailored to our industries. The reports can be found at www.mdu.com/sustainability.

These are some highlights of our recent efforts regarding sustainability:

- As our renewable generation resource capacity has increased, the carbon dioxide (CO_2) emission intensity of our electric generation resource fleet has been reduced by approximately 31% since 2003. We expect it to continue to decline with the planned retirements of the Lewis & Clark and Heskett 1 and 2 coal generation facilities.
- Renewable resources comprised approximately 27% of our current electric generation resource nameplate capacity.



- Approximately 26.5% of the electricity delivered to our customers from company-owned generation in 2019 was from renewable resources.
- We invested approximately $137 million in environmental emission control equipment and other environmental improvements at our coal-fired electric generation plants since 2013. The investments have resulted in substantial reductions in mercury, sulfur dioxide, nitrogen oxide, and filterable particulate emissions from our coal-fired electric generation resources.
- Montana-Dakota Utilities Co. produces renewable natural gas (RNG) from the Billings Regional Landfill in Montana. The project came online at the end of 2010 and has produced approximately 1.23 million dekatherm of RNG through year-end 2019. The RNG is supplied to the vehicle fuel market generating renewable identification numbers (RINS) and low carbon fuel standard (LCFS) credits in California and Oregon. In calendar year 2019, the Billings Landfill Plant produced approximately 1.63 million RINs and 4,303 LCFS credits.
- Our utility companies received high scores in customer satisfaction. Cascade Natural Gas Corporation ranked first nationwide for all gas utilities in the 2019 J.D. Power Gas Utility Residential Customer Satisfaction Study.[SM] In addition, Cascade Natural Gas Corporation ranked first, Intermountain Gas Company second, and Montana-Dakota Utilities Co. third among West Region mid-sized natural gas utilities in the 2019 J.D. Power Gas Utility Residential Customer Satisfaction Study.[SM]

- 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 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.
- The MDU Resources Foundation awarded grants of $1.57 million to educational and nonprofit institutions in 2019. Since its incorporation in 1983, the foundation has contributed more than $35.5 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. Eligible organizations are local 501(c) nonprofit organizations providing services in categories of civic and community activities, culture and arts, education, environment, and health and human services. In 2019, the foundation granted $60,000 under this program, matching over 7,900 employee volunteer hours.
- We encourage support of educational institutions by all employees. The MDU Resources Foundation matches contributions to educational institutions by employees up to $750.

26.5%
of 2019 Electricity Generated From Renewable Resources

Foundation Awarded
$1.57 Million
of Grants in 2019

31%
Reduction in CO_2 Intensity in Our Electric Generation Fleet Since 2003

BOARD OF DIRECTORS

ITEM 1. ELECTION OF DIRECTORS

The board currently consists of ten directors, all of whom are standing for election to the board at the 2020 Annual Meeting of Stockholders to hold office until the 2021 annual meeting and until their successors are duly elected and qualified.

The board has affirmatively determined that all the director nominees, other than David L. Goodin, our president and chief executive officer, are independent in accordance with New York Stock Exchange (NYSE) rules, our governance guidelines, and our bylaws.

Our bylaws provide for a majority voting standard for the election of directors. See "Additional Information - Majority Voting" below for further detail.

Each of the director nominees has consented to be named in this proxy statement and to serve as a director, if elected. We do not know of any reason why any nominee would be unable or unwilling to serve as a director, if elected. If, however, a nominee becomes unable to serve or will not serve, proxies may be voted for the election of such other person nominated by the board as a substitute or the board may choose to reduce the number of directors.

Information about each director nominee's share ownership is presented under "Security Ownership."

The shares represented by the proxies received will be voted for the election of each of the ten nominees named below unless you indicate in the proxy that your vote should be cast against any or all the director nominees or that you abstain from voting. Each nominee elected as a director will continue in office until his or her successor has been duly elected and qualified or until the earliest of his or her resignation, retirement, or death.

The ten nominees for election to the board at the 2020 annual meeting, all proposed by the board, are listed below with brief biographies. The nominees' ages are current as of December 31, 2019.

The board of directors recommends that the stockholders vote FOR the election of each nominee.

Director Nominees

Thomas Everist
Age 70

Independent Director Since 1995
Compensation Committee
Nominating and Governance Committee

Other Current Public Boards:
--Raven Industries, Inc.

Key Contributions to the Board: With a 44-year career in the construction materials and mining industry, Mr. Everist brings critical knowledge of the construction materials and contracting industry to the board. Mr. Everist also contributes strong business leadership and management capabilities and insights through his role as president and chair of his companies for over 32 years. His service on the board of another public company further enhances his contributions to the board.

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, since June 2006; 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 Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, since April 2011.
- Director of Showplace Wood Products, Inc., Sioux Falls, South Dakota, a custom cabinets manufacturer, since January 2000.
- 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 investing state funds, from July 2001 to June 2006.

Karen B. Fagg
Age 66

Independent Director Since 2005
Compensation Committee
Environmental and Sustainability Committee

Key Contributions to the Board: Through her management experience and knowledge in the fields of engineering, environment, and energy resource development, including four years as director of the Montana Department of Natural Resources and Conservation and over eight years as president, chief executive officer, and chair of her own engineering and environmental services company, as well as her service on a number of Montana state and community boards, Ms. Fagg contributes experience in responsible natural resource development with an informed perspective of the construction, engineering, and energy industries.

Career Highlights

- Vice president of DOWL LLC, dba DOWL HKM, an engineering and design firm, from April 2008 until her retirement in December 2011.
- President of HKM Engineering, Inc., Billings, Montana, an engineering and environmental services firm, from April 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 in April 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 SCL Health Montana Regional Board from January 2020 to present; and member of Carroll College Board of Trustees from 2005 through 2010 and August 2019 to present.
- Former member of several regional, state, and community boards, including director of St. Vincent's Healthcare from October 2003 to October 2009 and January 2016 through December 2019, including a term as chair; director of the Billings Catholic Schools Board from December 2011 through December 2018, including a term as chair; the First Interstate BancSystem Foundation from June 2013 to 2016; the Montana Justice Foundation from 2013 into 2015; Montana Board of Investments 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.

David L. Goodin
Age 58

Director Since 2013
President and Chief Executive Officer

Key Contributions to the Board: Serving as president and chief executive officer of MDU Resources Group, Inc. since 2013, Mr. Goodin is the only officer of the company that serves on our board. With 30 years of operating and leadership positions with our utility operations and seven years in his current position, he brings utility industry experience to the board as well as extensive knowledge of our company and its business operations. He contributes valuable insight into management's views and perspectives and 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 Center, since January 2011.
- Board member of the BSC Innovations Foundation, an extension of Bismarck State College providing curriculum to Saudi Arabia industries, since August 1, 2018.
- Former board member of numerous 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.

Mark A. Hellerstein
Age 67

Independent Director Since 2013
Audit Committee
Environmental and Sustainability Committee

Key Contributions to the Board: As a certified public accountant, on inactive status, with extensive financial experience through his employment as chief financial officer with several companies including public companies, Mr. Hellerstein provides knowledge of financial statements, corporate finance, and accounting matters to our board and audit committee. Mr. Hellerstein also contributes business leadership and public company management experience to the board as a result of 17 years of senior management and service as board chair of St. Mary Land & Exploration Company (now SM Energy Company).

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.

Dennis W. Johnson
Age 70

Independent Director Since 2001
Chair of the Board

Key Contributions to the Board: With over 45 years of experience in business management, manufacturing, and finance, holding positions as chair, president, and chief executive officer of TMI Group Incorporated for 38 years, as well as his prior service as a director of the Federal Reserve Bank of Minneapolis, Mr. Johnson brings operational, management, strategic planning, specialty contracting, and financial knowledge and insight to the board. Mr. Johnson also contributes significant knowledge of local, state, and regional issues involving North Dakota, the state where we are headquartered and have significant operations, resulting from his service on several state and local organizations.

Career Highlights

- Chair of the board of the company effective May 8, 2019; and vice chair of the board from February 15, 2018 to May 8, 2019.
- Chair, president, and chief executive officer of TMI Group Incorporated as well as its two wholly owned subsidiary companies, TMI Corporation and 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.

Patricia L. Moss
Age 66

Independent Director Since 2003
Compensation Committee
Environmental and Sustainability Committee

Other Current Public Boards:
--First Interstate BancSystem, Inc.
--Aquila Group of Funds

Key Contributions to the Board: With substantial experience in the finance and banking industry, including service on the boards of public banking and investment companies, Ms. Moss contributes broad knowledge of finance, business development, and compliance oversight, as well as public company governance, to the board. Through her business experience and knowledge of the Pacific Northwest, Ms. Moss also provides insight on state, local and regional economic and political issues where a significant portion of our operations and the largest number of our employees are located. Ms. Moss also contributes experience as a certified senior professional in human resources.

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

- Member of the Oregon Investment Council, which oversees the investment and allocation of all state of Oregon trust funds, since December 2018.
- 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. from 2014 to July 31, 2018; co-chair of the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, from May 2012 through December 2018; and a member of the Board of Trustees for the Aquila Group of Funds, whose core business is mutual fund management and provision of investment strategies to fund shareholders, from January 2002 to May 2005 (one fund) and from June 2015 to present (currently three funds).
- 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; and Clear Choice Health Plans Inc., a multi-state insurance company.

Edward A. Ryan
Age 66

Independent Director Since 2018
Audit Committee
Nominating and Governance Committee

Key Contributions to the Board: As an executive vice president and general counsel for a large public company with international operations, Mr. Ryan contributes expertise to the board in the areas of corporate governance, acquisitions, risk management, legal, compliance, and labor relations. Mr. Ryan also brings senior leadership, transactional, and public company experience.

Career Highlights

- Advisor to the chief executive officer and president of Marriott International from December 2017 to December 31, 2018.
- Executive vice president and general counsel of Marriott International from December 2006 to December 2017; senior vice president and associate general counsel from 1999 to November 2006; assumed responsibility for all corporate transactions and corporate governance in 2005; and joined Marriott International as assistant general counsel in May 1996.
- Private law practice from 1979 to 1996.

Other Leadership Experience

- Chair of Goodwill of Greater Washington, D.C., a non-profit organization whose mission is to transform lives and communities through education and employment, effective January 1, 2020, where he has served as a director since January 2015, including a term as vice chair from January 2019 through December 2019 and chair of the finance committee from January 2018 through December 2019.

David M. Sparby
Age 65

Independent Director Since 2018
Audit Committee
Nominating and Governance Committee

Key Contributions to the Board: With over 32 years of broad public utility management and leadership experience with a large public utility company, including positions as senior vice president and as chief financial officer, Mr. Sparby provides a broad understanding of the public utility and natural gas pipeline industries, including renewable energy expertise. His lengthy senior leadership experience with a public company also contributes to the board.

Career Highlights

- Senior vice president and group president, revenue, of Xcel Energy and president and chief executive officer of its subsidiary, NSP-Minnesota, from May 2013 until his retirement in December 2014; senior vice president and group president, from September 2011 to May 2013; chief financial officer from March 2009 to September 2011; and president and chief executive officer of NSP-Minnesota from 2008 to March 2009. He joined Xcel Energy, or its predecessor Northern States Power Company, as an attorney in 1982 and held positions of increasing responsibility.
- Attorney with the State of Minnesota, Office of Attorney General, from 1980 to 1982, during which period his responsibilities included representation of the Department of Public Service and the Minnesota Public Utilities Commission.

Other Leadership Experience

- Board of Trustees of Mitchell Hamline School of Law since July 2011, including executive committee and committee chair positions.
- Board of Trustees of the College of St. Scholastica since July 2012, including vice chair and executive committee positions.

Chenxi Wang
Age 49

Independent Director Since 2019
Audit Committee
Environmental and Sustainability Committee

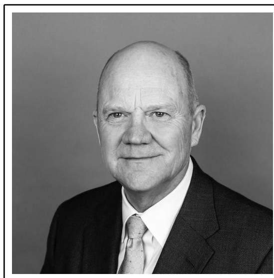
Key Contributions to the Board: Having significant technology and cybersecurity expertise through her management and leadership positions with several organizations, Ms. Wang contributes knowledge to the board on technology and cybersecurity issues. As the founder and managing general partner of a cybersecurity-focused venture fund, Ms. Wang also provides knowledge regarding capital markets and business development.

Career Highlights

- Founder and managing general partner of Rain Capital Fund, L.P., a cybersecurity-focused venture fund aiming to fund early-stage, transformative technology innovations in the security market with a goal of supporting women and minority entrepreneurs, since December 2017.
- Chief strategy officer at Twistlock, an automated and scalable cloud native cybersecurity platform, from August 2015 to February 2017.
- Vice president, cloud security & strategy of CipherCloud, a cloud security software company, from January 2015 to August 2015.
- Vice president of strategy of Intel Security, a company focused on developing proactive, proven security solutions and services that protect systems, networks, and mobile devices, from April 2013 to January 2015.
- Principal analyst and vice president of research at Forrester Research, a market research company that provides advice on existing and potential impact of technology, from January 2007 to April 2013.
- Assistant research professor and associate professor of computer engineering at Carnegie Mellon University from September 2001 through August 2007.

Other Leadership Experience

- Technical Board of Advisors of Secure Code Warriors, a Sydney-based cybersecurity company, since June 2019.
- Board of directors of OWASP Global Foundation, a nonprofit global community that drives visibility and evolution in the safety and security of the world's software, from January 2018 to December 2019, including a term as vice chair.
- Recipient of the 2019 Investor in Women Award by Women Tech Founders Foundation, an organization dedicated to advancing women in the tech industry.
- Board of advisors of Keyp GmbH, a Munich-based software company with a mission to provide enterprises convenient access to the digital identity ecosystem, from December 2017 to August 2019.
- Program co-chair (security and privacy track) for the Grace Hopper Conference 2016 and 2017, the world's largest gathering of women in computing.



John K. Wilson
Age 65

Independent Director Since 2003
Compensation Committee
Nominating and Governance Committee

Key Contributions to the Board: As a certified public accountant, on inactive status, with extensive finance and accounting experience through his employment with a major accounting firm and senior leadership positions with other firms, including a public utility, as well as his experience with mergers and acquisitions, Mr. Wilson contributes important oversight perspectives to the board, particularly in the fields of finance, accounting, and business management. He also provides valuable business leadership expertise and knowledge of the public utility industry.

Career Highlights

- Executive director of the Robert B. Daugherty Foundation in Omaha, Nebraska, since January 2010.
- President of Durham Resources, LLC, a privately held financial management company in Omaha, Nebraska, from 1994 to December 31, 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.
- 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.

Additional Information - Majority Voting

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected and which we do not anticipate, directors will be elected by a plurality of the votes cast.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock "for" all directors nominated by the board of directors. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes "against" than votes "for" election at our annual meeting of stockholders; and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee's recommendation no later than 90 days following the date of the annual meeting.

Brokers may not vote your shares on the election of directors if you have not given your broker specific instructions on how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

Board Evaluations and Process for Selecting Directors

In the annual board evaluation process, the nominating and governance committee evaluates our directors considering the current needs of the board and the company. In addition, during the year, the committee discusses board succession and reviews potential candidates. Although the committee may also retain a third party to assist in identifying potential nominees, none were retained in 2019.

Our annual board evaluation process involves assessments at the board and board committee levels. These annual evaluations are conducted by the chair of the nominating and governance committee and periodically by an independent third party.

Our governance guidelines provide that directors are not eligible to be nominated or appointed to the board if they are 76 years or older at the time of the election or appointment. Term limits on directors' service have not been instituted.

Director Qualifications, Skills, and Experience

Director nominees are chosen to serve on the board based on their qualifications, skills, and experience, as discussed in their biographies, and how those characteristics supplement the resources and talent on the board and serve the current needs of the board and the company.

In making its nominations, the nominating and governance committee also assesses each director nominee by a number of key characteristics, including character, success in a chosen field of endeavor, background in publicly traded companies, independence, and willingness to commit the time needed to satisfy the requirements of board and committee membership. Although the committee has no formal policy regarding diversity, in recommending director nominees the committee considers diversity in gender, ethnic background, geographic area of residence, skills, and professional experience.

The following shows core specialized competencies and other characteristics of the director nominees.

CORE SPECIALIZED COMPETENCES

EXECUTIVE MANAGEMENT/PUBLIC COMPANY
Served as CEO or other senior executive of an organization or as a director of another publicly traded company

100%

INDUSTRY EXPERIENCE
Experience in our businesses and related industries, including public utilities, natural gas pipelines, construction, and aggregate mining

60%

ACCOUNTING/FINANCE
Experience in the preparation and review of financial statements and financial reports

50%

LEGAL/CORPORATE GOVERNANCE
Experience in dealing with complex legal and public company governance issues

50%

CAPITAL MARKETS
Experience overseeing company financings, investments, capital structures, and financial strategy

60%

ENVIRONMENT/SCIENCE
Experience addressing environmental and sustainability issues relating to our businesses

50%

INFORMATION TECHNOLOGY/CYBERSECURITY
Oversight of or significant background working with information technology systems, data management and cybersecurity risks

10%

GOVERNMENT/REGULATORY/PUBLIC AFFAIRS
Background or experience in governmental regulations and public policy issues affecting our businesses

60%

RISK MANAGEMENT AND COMPLIANCE
Regulatory and compliance expertise or experience in the identification, assessment and mitigation of risks facing our company

100%

INDEPENDENCE

The company's corporate governance guidelines require that a substantial majority of the board must be independent. The board has determined that all director nominees, other than Mr. Goodin, meet the independence standards set by the NYSE and SEC.

90%

Nominee Independence

TENURE

The average tenure of the director nominees is approximately 10.5 years, which reflects a balance of company experience and new perspectives.

# of Years of Service	Nominees
0-4	3
5-10	2
11+	5

GENDER DIVERSITY

The board is committed to having a diverse and broadly inclusive membership. Three of our 10 director nominees are women.

70% 30%

Board Composition and Refreshment

The nominating and governance committee is focused on ensuring that the board reflects a diversity of experience, skills, and backgrounds. Each of the current directors has been nominated for election to the board of directors upon recommendation by the nominating and governance committee and each has decided to stand for election.

With the retirement of former board members Harry J. Pearce and William E. McCracken at the 2019 annual meeting, the committee identified qualified director candidates with commensurate experience and background as replacement board members. In evaluating the board retirements and current needs of the board and the company, the nominating and governance committee focused on identifying board candidates that would add gender diversity to the board as well as background and core competencies in the fields of technology, cybersecurity, and public company governance. Potential director nominees were brought to the attention of the nominating and governance committee by board members, management, organizations, and database searches.

The nominating and governance committee continues to identify individuals as potential board of director candidates, particularly individuals with industry experience to support the company's strategy to grow its two business platforms of regulated energy delivery and construction materials and services.

By tenure, if the nominees are elected, the board will be comprised of three directors who have served from 0-4 years, two directors who have served from 5-10 years, and five directors who have served over 11 years. This mix provides a balance of experience and institutional knowledge with fresh perspectives.

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 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 nonprofit organizations where a director or their spouse serves or served as a director, chair, or vice chair of the board of trustees, trustee, or member of the organization or related entity:* The Foundation made charitable contributions to three such nonprofit organizations that collectively amounted to $8,650 in 2019. None of the contributions made to any of the nonprofit entities exceeded 2% of the relevant entity's consolidated gross revenues.

- *Business relationships with entities with which a director or director nominee is affiliated*: 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 approximately $900,000 in 2019 directly or through a third party 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 HDR, Inc. services and the relationship did not affect his independence under our corporate governance guidelines or the NYSE listing standards.

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.

Sustainability and Social Responsibility

We view corporate responsibility as critical to our sustainability. While we are always focused on delivering strong financial performance, we are committed to doing so in a responsible manner that recognizes and respects the interests of all our stakeholders.

In recognition of its social responsibility and sustainability commitments, the board of directors in May 2019 formed the environmental and sustainability committee as a standing committee of the board with particular focus on our environmental, workplace health, safety, human capital, and other social sustainability programs and performance. Our environmental and sustainability committee is discussed further on page 22.

Also in 2019, the company issued an updated and expanded sustainability report based upon standards outlined by the Sustainability Accounting Standards Board or other industry organizations for each of our segment industries to provide investors and other interested stakeholders with information regarding our sustainability efforts. The sustainability report can be found on our website at http://www.mdu.com/sustainability.

In August 2019, the Business Roundtable issued a statement on corporate social responsibility stating that its members share a fundamental commitment to all their stakeholders: customers, employees, suppliers, communities, and stockholders. With the company's origin and rich history in providing electric and natural gas utility service to rural communities in the Dakotas and Montana, our utility companies have long operated under the motto, "In the Community to Serve®." With the addition of our construction businesses to our legacy of regulated energy delivery businesses, we define our purpose as "Building a Strong America®" in recognition of our mission to deliver value to our stakeholders. In 2007, the company adopted its Leading with Integrity Guide, which sets out our commitments to stakeholders:

- **Commitment to Integrity.** We will conduct the corporation's business legally and ethically with our best skills and judgment.
- **Commitment to Shareholders.** We will always act in the best interests of the corporation and protect its assets.
- **Commitment to Employees.** We will work together to provide a safe and positive workplace.
- **Commitment to Customers, Suppliers, and Competitors.** We will compete in business only by lawful and ethical means.
- **Commitment to Communities.** We will be a responsible and valued corporate citizen.

Further detail on our commitments to our stakeholders can be found at http://www.mdu.com/commitmenttointegrity.

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. Management regularly attends and presents at investor and financial conferences and holds one-on-one meetings with investors and also interacts directly with investors and analysts during our quarterly earnings conference calls. During 2019, the company held meetings, conference calls, and webcasts with a diverse mix of stockholders including meetings or telephone conferences with eleven of the institutional investors included in our year-end top 30 stockholders. In our meetings or conferences, we discussed a variety of topics, including company strategy and our capital expenditure forecast; operational and financial updates; environmental, social, and corporate governance issues; sustainability; and, previously announced strategic initiatives. Feedback from engagements is shared by management with the board and its committees, and the discussions with some of our investors included the chair of our board of directors giving those stockholders the opportunity to provide feedback directly to a member of our board. The company also held telephone conferences with a proxy advisory firm to discuss corporate governance, executive compensation practices, and other topics.

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 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 chair, particularly as the board's oversight responsibilities continue to grow and demand more time and attention. The fundamental role of the board of directors is to provide oversight of the management of the company in good faith and in the best interests of the company and its stockholders. Having an independent 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. With the retirement of Mr. Pearce at the 2019 annual meeting, the board elected Mr. Johnson as its independent chair at its May 2019 board meeting.

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, strategic risks, operational 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 and mitigation strategies, and providing information regarding material risks and risk management and mitigation 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 chief executive officer 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. Senior management annually presents an assessment to the board of critical enterprise risks that threaten the company's strategy and business model including risks inherent in the key assumptions underlying the company's business strategy for value creation. Periodically, the board receives presentations from external experts on matters of strategic importance to the board. At least annually, the board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

The company has also developed a robust compliance program to promote a culture of compliance, consistent with the right tone at the top, to mitigate risk. The program includes training and adherence to our code of conduct and legal compliance guide. We further mitigate risk through our internal audit and legal departments.

While the board is ultimately responsible for risk oversight at our company, our 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, cybersecurity, 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. The audit committee receives regular reports on the company's compliance program, including reports received through our anonymous reporting hot line. It also receives reports and regularly meets with the company's external and internal auditors. During its quarterly meetings in 2019, the audit committee received presentations or reports from management on cybersecurity and the company's mitigation of cybersecurity risks. The entire board was present for the presentations and had access to the reports. Risk assessment and mitigation 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, board membership and structure, succession planning for our directors and executive officers, and corporate governance.

- The environmental and sustainability committee was established in May 2019 and assists the board in fulfilling its oversight responsibilities with respect to the management of risks related to environmental matters, physical and other workplace hazards, employee and public safety, and other social sustainability matters.

Board Meetings and Committees

During 2019, the board of directors held four regular meetings and one special meeting. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2019 (held during the period he or she was a director). Directors are encouraged to attend our annual meeting of stockholders. All but one director attended our 2019 Annual Meeting of Stockholders.

The board has standing audit, compensation, nominating and governance, and environmental and sustainability committees which meet at least quarterly. Following the 2019 annual meeting and the establishment of the environmental and sustainability committee, new chairs were elected to the standing committees, and membership changes were made to each committee. The table below provides current committee membership.

Name	Audit Committee	Compensation Committee	Nominating and Governance Committee	Environmental and Sustainability Committee
Thomas Everist		●	●	
Karen B. Fagg		●		C
Mark A. Hellerstein	●			●
Patricia L. Moss		●		●
Edward A. Ryan	●		C	
David M. Sparby	C		●	
Chenxi Wang	●			●
John K. Wilson		C	●	

C - Chair

● - 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 2019

The nominating and governance committee met four times during 2019. The current committee members are Edward A. Ryan, chair, Thomas Everist, David M. Sparby, and John K. Wilson.

The nominating and governance committee is governed by a written charter and 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 director nominees 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, management, consultants, organizational representatives, and other individuals likely to possess an understanding of our business and knowledge concerning suitable director candidates.

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 these considerations annually in connection with the nomination of directors for election at the annual meeting of stockholders. The committee seeks a collective background of board members to provide a portfolio of experience and knowledge that serves the company's governance and strategic needs and best perpetrates our long-term success. Directors should have demonstrated experience and knowledge that is relevant to the board's oversight role of the company's business. The nominating and governance committee also considers the board's diversity in recommending nominees, including diversity of experience, expertise, ethnicity, gender, and geography. The composition of the current board and the board nominees reflects diversity in business and professional experience, skills, ethnicity, gender, and geography.

Audit Committee

Met Eight Times in 2019

The audit committee is a separately-designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 and is governed by a written charter.

The audit committee met eight times during 2019. The current audit committee members are David M. Sparby, chair, Mark A. Hellerstein, Edward A. Ryan, and Chenxi Wang. The board of directors has determined that Messrs. Sparby and Hellerstein are "audit committee financial experts" as defined by SEC rules, and all audit committee members are financially literate within the meaning of the listing standards of the NYSE. All members 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 committee reviews and discusses with management and the independent auditors, before filing with the SEC, the annual audited financial statements and quarterly financial statements. The audit committee also:

- 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;
  - discussions with management regarding the company's earnings releases and guidance;
  - the independent registered public accounting firm's qualifications and independence;
  - the appointment, compensation, retention, and oversight of the work of the independent registered public accounting firm;
  - the performance of our internal audit function and independent registered public accounting firm;
  - management of risk in the audit committee's areas of responsibility, including cybersecurity, financial reporting, legal and regulatory compliance, and internal controls; 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.

Compensation Committee

Met Four Times in 2019

During 2019, the compensation committee met four 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 non-employee directors for purposes of Rule 16-b under the Exchange Act. Current members of the compensation committee are John K. Wilson, chair, Thomas Everist, Karen B. Fagg, and Patricia L. Moss.

The compensation committee is governed by a written charter and assists the board of directors in fulfilling its responsibilities relating to the company's compensation policies and programs. It has direct responsibility for determining compensation for our Section 16 officers and for overseeing the company's management of compensation risk in its areas of responsibility. The compensation committee also 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 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. 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. In 2018, the compensation committee retained a compensation consultant, Meridian Compensation Partners, LLC ("Meridian"), to conduct a competitive analysis on executive compensation for 2019. In 2019, the human resources department conducted the executive officer market analysis of the Section 16 officers with a review of the analysis by the compensation consultant, Meridian. Prior to retaining an adviser, the compensation committee considers 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 Meridian to assist in its potential conflicts of interest assessment. Based on its review and analysis, the compensation committee determined in 2019 that Meridian 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. In 2019, the analysis of non-employee director compensation was performed by the compensation consultant, Meridian.

Environmental and Sustainability Committee

Met Two Times in 2019

The environmental and sustainability committee was formed by the board of directors in May 2019 and met twice during the balance of 2019. The committee is governed by a written charter and consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the listing standards of the NYSE. The current members of the committee are Karen B. Fagg, chair, Mark A. Hellerstein, Patricia L. Moss, and Chenxi Wang.

The environmental and sustainability committee oversees and provides recommendations to the board with respect to the company's policies, strategies, public policy positions, programs, and performance related to environmental, workplace health, safety, and other social sustainability matters. The environmental and sustainability committee:

- reviews significant risks regarding environmental and social sustainability matters that fundamentally affect the company's business interests and long-term viability;
- reviews the company's environmental and social sustainability strategies, policies, processes, programs, and performance;
- reviews recent and emerging environmental and social sustainability matters;

- reviews labor and human relations issues related to the company's operations;
- reviews any fatality, serious injury, or illness involving an employee, customer, contractor, or third-party occurring in connection with the company's operations;
- reviews any material noncompliance by the company with environmental, health, and safety laws and regulations;
- reviews the company's efforts to advance progress on sustainable development;
- reviews methods to communicate the company's environmental and social sustainability values and performance;
- considers and advises the compensation committee on the company's performance with respect to incentive compensation metrics relating to environmental and social sustainability matters;
- reports to, advises, and makes recommendations to the board on environmental and social sustainability matters affecting the company;
- reviews the company's environmental and social sustainability disclosures;
- reviews stockholder proposals related to environmental and social sustainability matters; and
- reviews significant legislative, regulatory, political, and social issues and trends that may affect the company's environmental, sustainability, health, and safety management processes and systems.

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.

Executive Sessions of the Independent Directors

The non-employee directors meet in executive session at each regularly scheduled quarterly board of directors meeting. The chair of the board presides at the executive session of the non-employee directors.

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 2019, no directors or director nominees submitted resignations under this requirement.

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 two other public company boards. 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 focus 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, geography, 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 mandatory retirement age allows us to benefit from experienced directors, with industry expertise, company institutional knowledge and 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, Harry J. Pearce and William E. McCracken retired as directors at the completion of their term following the 2019 annual meeting. Two replacement members were added to the board of directors. Edward A. Ryan was appointed to the board of directors in November 2018, and subsequently elected to the board in May 2019, and Chenxi Wang was elected to the board of directors in May 2019.

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 applicable procedures set forth in Section 2.08 or 2.10 of our bylaws. Our bylaws are available on our website. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2021 Annual Meeting" in the section entitled "Information about the Annual Meeting" for further details.

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.

Proxy Access

Our bylaws allow stockholders to nominate directors for inclusion in our proxy statement subject to the following parameters:

Ownership Threshold:	3% of outstanding shares of our common stock
Nominating Group Size:	Up to 20 stockholders may combine to reach the 3% ownership threshold
Holding Period:	Continuously for three years
Number of Nominees:	The greater of two nominees or 20% of our board

We believe these proxy access parameters reflect a well designed and balanced approach to proxy access that mitigates the risk of abuse and protects the interests of all of our stockholders. Stockholders who wish to nominate directors for inclusion in our Proxy Statement in accordance with proxy access must follow the procedures in Section 2.10 of our bylaws. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2021 Annual Meeting."

One Class of Stock

Our common stock is the only class of shares outstanding.

No Shareholder Rights Plan

We do not have a “poison pill” and have no intention of adopting one at this time.

Annual Say-on-Pay Advisory Vote

Stockholders annually vote on the company’s named executive officer compensation.

Cybersecurity Oversight

The audit committee receives periodic briefings concerning cybersecurity, information security, technology risks, and risk mitigation programs.

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/governance
• Corporate Governance Guidelines	http://www.mdu.com/governance
• Board Committee Charters for the Audit, Compensation, Nominating and Governance, and Environmental and Sustainability Committees	http://www.mdu.com/governance
• Leading With Integrity Guide	http://www.mdu.com/commitmenttointegrity

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 requires the audit committee to review any transaction, arrangement or relationship, or series thereof:

- in which the company was or will be a participant;
- the amount involved exceeds $120,000; and
- a related person had 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 2019.

COMPENSATION OF NON-EMPLOYEE DIRECTORS

Director Compensation for 2019

MDU Resources' non-employee directors are compensated for their service according to the MDU Resources Group Inc. Director Compensation Policy. Only one company 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. The company's independent consultant provided the director compensation analysis for 2019. 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 concurred that the annual compensation for non-employee directors be set at:

Base Cash Retainer[1]	$85,000
Additional Cash Retainers:	
Non-Executive Chair	95,000
Audit Committee Chair	20,000
Compensation Committee Chair	15,000
Nominating and Governance Committee Chair	15,000
Environmental and Sustainability Committee Chair	15,000
Annual Stock Grant[2] - Directors (other than Non-Executive Chair)	125,000
Annual Stock Grant[3] - Non-Executive Chair	150,000

[1] Cash retainer amounts shown were effective June 1, 2019, when the base retainer was increased by $15,000 and the retainer for the board chair and committee chairs were each increased by $5,000.

[2] The annual stock grant is a grant of shares of company common stock equal in value to $125,000.

[3] The annual stock grant is a grant of shares of company common stock equal in value to $150,000.

There are no meeting fees paid to directors.

The following table outlines the compensation paid to our non-employee directors for 2019.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)[1]	All Other Compensation ($)[2]	Total ($)
Thomas Everist	82,917	125,000	5,083	213,000
Karen B. Fagg	91,667	125,000	2,083	218,750
Mark A. Hellerstein	78,750	125,000	3,683	207,433
Dennis W. Johnson	140,417	141,667	3,683	285,767
William E. McCracken[3]	29,167	52,083	35	81,285
Patricia L. Moss	78,750	125,000	2,083	205,833
Harry J. Pearce[3]	66,667	62,500	5,035	134,202
Edward A. Ryan	87,500	125,000	3,683	216,183
David M. Sparby[4]	90,417	125,000	5,083	220,500
Chenxi Wang	55,417	83,333	48	138,798
John K. Wilson	87,500	125,000	1,583	214,083

1 Directors receive an annual payment of $125,000 in company common stock, except the non-executive chair who receives $150,000 in company common stock, under the MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan. Directors serving less than a full year receive a prorated stock payment based on the number of months served. All stock payments 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 19, 2019, which was $29.16 per share. The amount paid in cash for fractional shares is included in the amount reported in the stock awards column to this table. As of December 31, 2019, there are no outstanding stock awards or options associated with 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. Amounts for life insurance premiums reflect prorated amounts for directors serving less than a full year based on the number of months served.

3 Messrs. McCracken and Pearce retired from the board on May 7, 2019.

4 Mr. Sparby elected to receive shares of our common stock in lieu of his $90,417 of fees earned in cash. He received a total of 3,295 shares of company common stock which was purchased during 2019 on March 29, June 28, September 30, and December 31 at market prices of $25.66, $25.47, $28.39, and $29.54, respectively.

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 their beneficiaries during the time they serve 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 2019.

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 beneficially 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 received through our Non-Employee Director Long-Term Incentive Compensation Plan are considered in ownership calculations as well as other beneficial ownership of our common stock by a spouse or other immediate family member residing in the director's household. A director is allowed five years commencing January 1 of the year following the year of the 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 or are within the first five years of their election to the board. 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, each named executive officer, and all directors and executive officers as a group owned beneficially as of February 29, 2020. 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[1]	Shares of Common Stock Beneficially Owned	Percent of Class
David C. Barney	46,381 [2,3]	*
Thomas Everist	865,978	*
Karen B. Fagg	78,179	*
David L. Goodin	280,772 [2]	*
Mark A. Hellerstein	28,286	*
Dennis W. Johnson	99,224 [4]	*
Nicole A. Kivisto	63,182 [2,5]	*
Patricia L. Moss	80,614	*
Edward A. Ryan	18,476	*
David M. Sparby	14,807	*
Jeffrey S. Thiede	47,920 [2]	*
Jason L. Vollmer	12,721 [2]	*
Chenxi Wang	2,857	*
John K. Wilson	133,887	*
All directors and executive officers as a group (18 in number)	1,884,869 [2,6]	*

* Less than one percent of the class. Percent of class is calculated based on 200,474,914 outstanding shares as of February 29, 2020.

1 The table includes the ownership of all current directors, named executive officers, and other executive officers of the company without naming them.

2 Includes full shares allocated to the officer's account in our 401(k) retirement plan.

3 The total includes 687 shares owned by Mr. Barney's spouse.

4 Mr. Johnson disclaims all beneficial ownership of the 163 shares owned by his spouse.

5 The total includes 531 shares owned by Ms. Kivisto's spouse.

6 Includes shares owned by a director's or executive's spouse regardless of whether the director or executive claims beneficial ownership.

Hedging Policy

The company's Director Compensation Policy and its Executive Compensation Policy prohibit our directors and executives from hedging their ownership of company stock. The Director Compensation Policy applies to all directors who are not full-time employees of the company. The Executive Compensation Policy applies to the executives of the company designated as an officer for purposes of Section 16 of the Securities Exchange Act of 1934 as well as all other executives of the company and its subsidiaries who participate in its Long-Term Performance-Based Incentive Plan and its Executive Incentive Compensation Plan. Under the policies, directors and executives are prohibited from engaging in transactions that allow them to own stock technically but without the full benefits and risks of such ownership, including, but not limited to, zero-cost collars, equity swaps, straddles, prepaid variable forward contracts, security futures contracts, exchange funds, forward sale contracts, and other financial transactions that allow the director or executive to benefit from the devaluation of the company's stock.

The company policies also prohibit directors, executives, and related persons from holding company 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.

Greater Than 5% Beneficial Owners

Based solely on filings with the SEC, the table below shows information regarding the beneficial ownership of more than five percent of the outstanding shares of our common stock.

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	20,929,217 [1]	10.44%
Common Stock	**BlackRock, Inc.** 55 East 52nd Street New York, NY 10055	20,068,550 [2]	10.00%
Common Stock	**State Street Corporation** State Street Financial Center One Lincoln Street Boston, MA 02111	13,740,378 [3]	6.86%

[1] Based solely on the Schedule 13G, Amendment No. 8, filed on February 12, 2020, The Vanguard Group reported sole dispositive power with respect to 20,801,988 shares, shared dispositive power with respect to 127,229 shares, sole voting power with respect to 110,365 shares, and shared voting power with respect to 46,984 shares. These shares include 76,663 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 80,686 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. 11, filed on February 4, 2020, BlackRock, Inc. reported sole voting power with respect to 18,902,771 shares and sole dispositive power with respect to 20,068,550 shares as the parent holding company or control person of BlackRock Life Limited; BlackRock International Limited; BlackRock Advisors, LLC; BlackRock (Netherlands) B.V.; BlackRock Fund Advisors; 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 Asset Management North Asia Limited; and BlackRock Fund Managers Ltd.

[3] Based solely on the Schedule 13G, filed on February 14, 2020, State Street Corporation reported shared voting power with respect to 13,343,597 shares and shared dispositive power with respect to 13,740,378 shares as the parent holding company or control person of SSGA Funds Management, Inc., State Street Global Advisors Limited (UK), State Street Global Advisors LTD (Canada), State Street Global Advisors Asia LTD, State Street Global Advisors Singapore LTD, State Street Global Advisors GmbH, State Street Global Advisors Ireland Limited, and State Street Global Advisors Trust Company.

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, the compensation committee and board of directors believe the current executive compensation program directly links compensation of the named executive officers to our financial performance and aligns the interests of the named executive officers with those of our stockholders. The compensation committee and board of directors also believe the executive compensation program provides the 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 the named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy for 2019 was built on a foundation of these guiding principles:

- we pay for performance, with over 65% of our 2019 total target direct compensation for the named executive officers in the form of performance-based incentive compensation;
- we review competitive compensation data for the 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 earnings before interest, taxes, depreciation, and amortization (EBITDA); and
- we align executive compensation and performance by using long-term performance incentives based on total stockholder return relative to our peer group and financial measures important to company growth.

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 2019. Accordingly, the following resolution is submitted for stockholder vote at the 2020 annual meeting:

> "RESOLVED, that the compensation paid to the company's named executive officers, as disclosed pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables, and narrative discussion of this Proxy Statement, is hereby approved."

As this is an advisory vote, the results will not be binding on the company, the board of directors, or the compensation committee and will not require us to take any action. The final decision on the compensation of the named executive officers remains with the compensation committee and the board of directors, although the 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" 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 the named executive officers requires the affirmative vote of a majority of the 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

Information concerning the executive officers, including their ages as of December 31, 2019, 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	58	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	64	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013, and president effective January 1, 2012.
Trevor J. Hastings	46	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	56	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	46	Ms. Kivisto was elected president and chief executive officer of Montana-Dakota Utilities 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	66	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	53	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	57	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	42	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 2019 and how their 2019 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 2019 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.

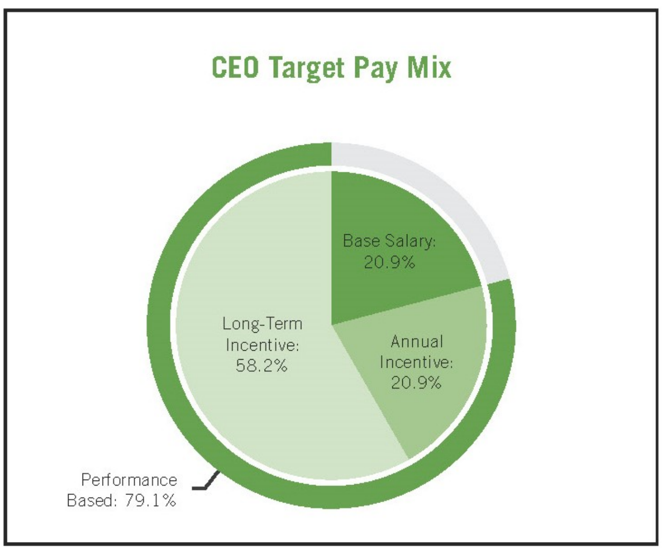
Our Named Executive Officers for 2019 were:

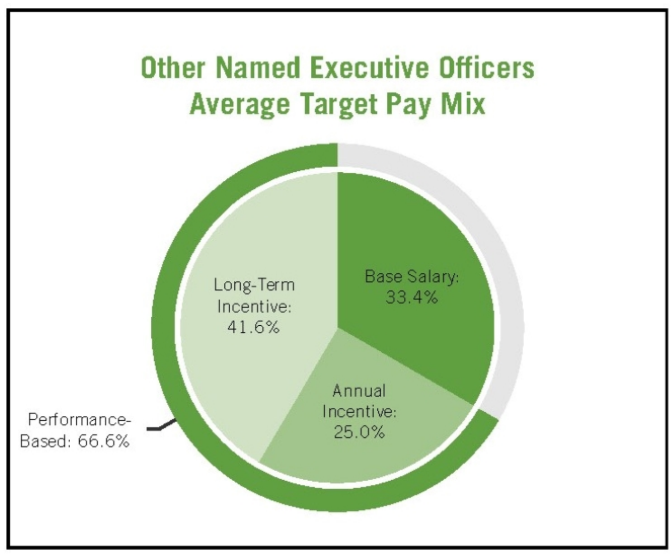
David L. Goodin	President and Chief Executive Officer (CEO)
Jason L. Vollmer	Vice President, Chief Financial Officer (CFO) and Treasurer
David C. Barney	President and Chief Executive Officer - Construction Materials and Contracting Segment
Jeffrey S. Thiede	President and Chief Executive Officer - Construction Services Segment
Nicole A. Kivisto	President and Chief Executive Officer - Electric and Natural Gas Distribution Segments

Executive Summary

Pay for Performance

The compensation committee is responsible for designing and approving our executive compensation program and setting compensation opportunities for named executive officers. Our compensation program is directly linked to our business strategy to ensure officers are focused on elements that drive our business strategy and create stockholder value. To ensure management's interests are aligned with those of our stockholders and the performance of the company, the significant majority of the CEO's and the other 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 named executive officers, including base salary and the annual and long-term 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 relatively 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 base salary is competitive as measured against the base salaries of similarly situated executives in our peer group and market compensation data.

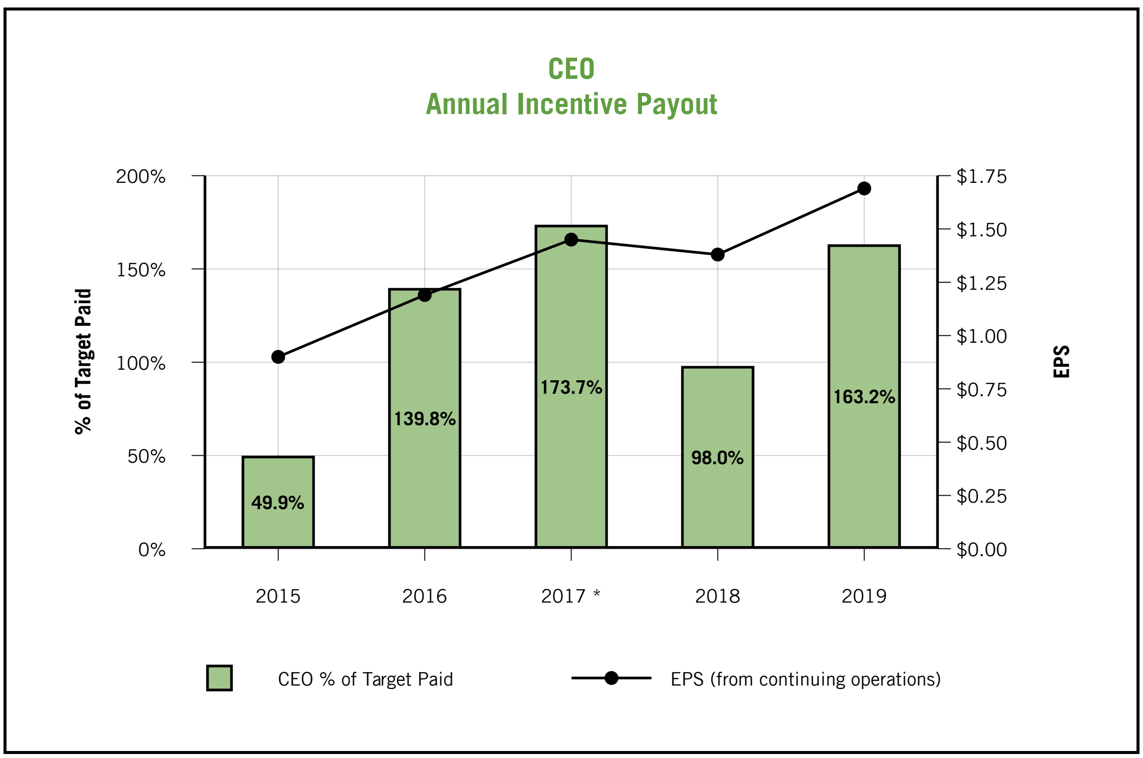
Annual Cash Incentive Awards

Annual cash incentive awards for our executive officers are linked to performance by rewarding achievement of 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 2019 was the same as the design used in 2018. 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 the achievement of the executive's performance measures.

The compensation committee selected specific business segment financial performance measures for the business segment executives which represented 80% of their annual incentive award opportunity. The other 20% of the business segment executives' annual incentive 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 the performance measures for each business segment executive and weighted by each business segment's invested capital relative to the company's total invested capital. Each corporate executive's target award is multiplied by the sum of the weighted achievement percentage for each business segment executive to derive the corporate 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.

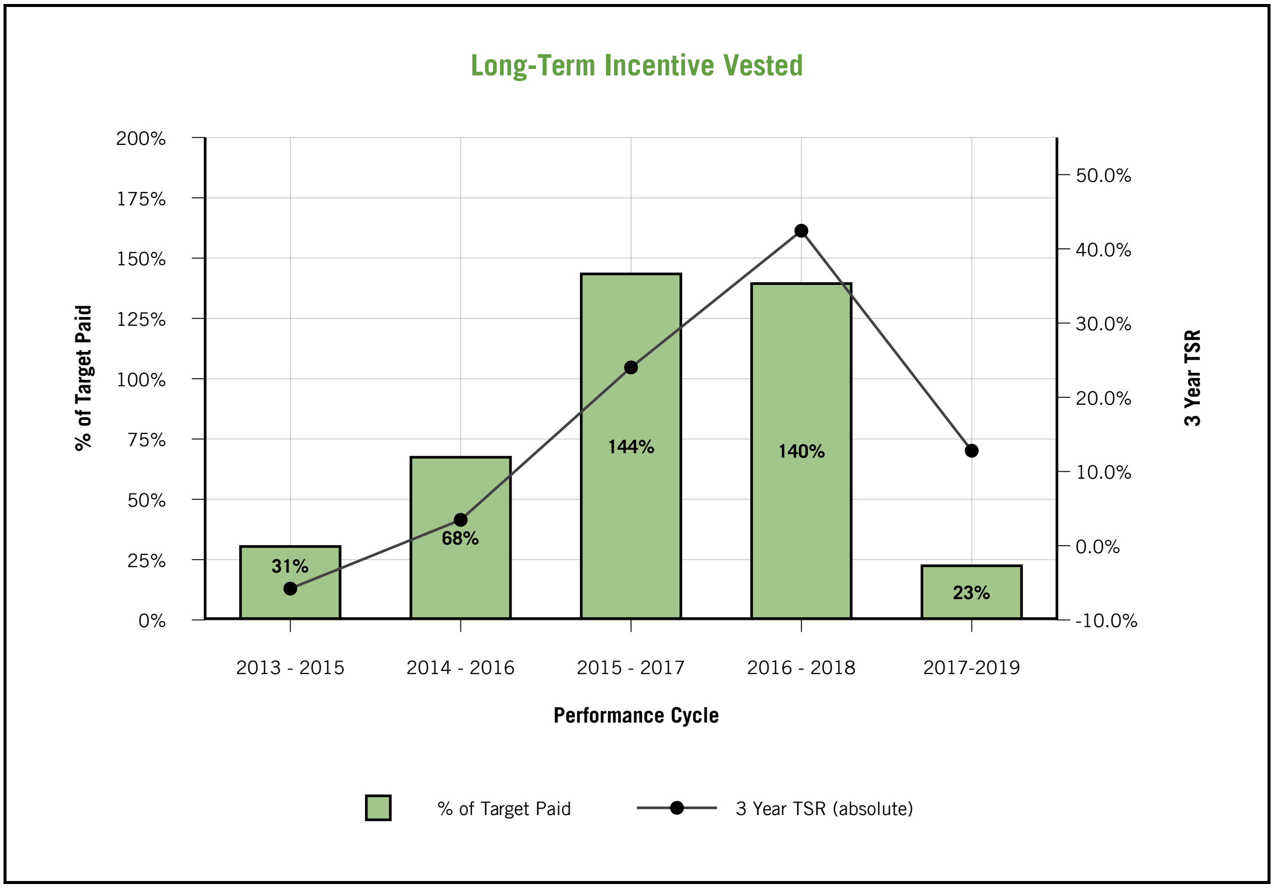
The following chart shows the percentage payout of the annual incentive target realized by our CEO compared to earnings per share from continuing operations for the last five years. The chart demonstrates the alignment between our financial performance and realized annual cash incentive compensation.



* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of $1.45 per share which included a non-recurring benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act that was signed into law on December 22, 2017.

Long-Term Equity-Based Incentive Awards

Our compensation committee and the board approve grants of long-term incentives to our executives in the form of performance shares which vest into company stock plus dividend equivalents at the end of a three-year performance cycle upon achievement of established performance measures. The following chart depicts the actual vesting percentage for the last five performance cycles and demonstrates the alignment between total stockholder return (TSR) and realized long-term incentive compensation by our executives.



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 officer's compensation dependent on the achievement of robust 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 2019 Annual Meeting of Stockholders, 96.8% of the votes cast on the "Say on Pay" proposal approved the compensation of our named executive officers. The compensation committee viewed the 2019 vote as an expression of the stockholders general satisfaction with the company's executive compensation programs. The compensation committee reviewed and considered the 2019 vote on "Say on Pay" in setting compensation for 2020 by continuing to link performance-based annual and long-term incentives to company financial performance and stockholder 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 executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, business segment economic environment, and the actual performance of the overall company and the business segments.
- ☑ **Annual Cash Incentive** - Payment of annual cash incentive awards are based on business segment and overall company performance against pre-established annual financial measures.
- ☑ **Long-Term Equity Incentive** - Long-term incentive awards may be earned at the end of a three-year period based on achieving pre-established performance measures and are paid through performance shares which encourages stock ownership and helps retain management talent.
- ☑ **Balanced Mix of Pay Components** - The target compensation mix is not overly weighted toward annual incentive awards but rather represents a balance of annual cash and long-term equity-based compensation.
- ☑ **Mix of Financial Goals** - Use of a mixture of financial goals to measure performance prevents overemphasis on a single metric.
- ☑ **Annual Compensation Risk Analysis** - Risks related to our compensation programs are regularly analyzed through an annual compensation 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. Our president and chief executive officer is required to own stock equal to four times his base salary, and the other named executive officers are required to own stock equal to three times their base salary. The executive officers also must 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. Net performance shares must also be held until share ownership requirements have been met.
- ☑ **Clawback Policy** - If the company's audited financial statements are restated due to any material noncompliance with the financial reporting requirements under the securities laws, 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.

What We Do Not Do

- ☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.
- ☒ **Employment Agreements** - Executives do not have employment agreements entitling them to specific payments upon termination or a change of control of the company.
- ☒ **Perquisites** - Executives do not receive perquisites that materially differ from those available to employees in general.
- ☒ **Hedge Stock** - Executives are not allowed to hedge company securities.
- ☒ **Pledge Stock** - Executives 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.
- ☒ **Tax Gross-Ups** - Executives do not receive tax gross-ups on their compensation except for circumstances regarding relocation.

2019 Compensation Framework

Objectives of our Compensation Program

We have a written executive compensation policy for our executive officers, including all the named executive officers. Our policy's stated objectives are to:

- recruit, motivate, reward, and retain high performing executive talent required to create superior shareholder value;
- reward executives for short-term performance as well as for growth in enterprise value over the long-term;
- ensure effective utilization and development of talent by working in concert with other management processes - for example, performance appraisal, succession planning, and management development;
- help ensure that compensation programs do not encourage or reward excessive or imprudent risk taking; and
- provide a competitive package relative to industry-specific and general industry comparisons and internal equity, as appropriate.

Compensation Decision Process for 2019

For 2019, 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 compensation committee meetings but was not present during discussions of his compensation. At its meetings in November 2018 and February 2019, the compensation committee established and approved base salaries and performance measures for the annual and long-term incentive compensation for 2019. It also certified the achievement of performance measures for 2018 associated with annual and long-term incentive compensation that was paid or vested in 2019.

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 has been performed by the company's human resources department using a variety of industry specific sources. In August 2018, the compensation committee's consultant, Meridian Compensation Partners LLC, prepared the analysis of and provided recommendations for the 2019 executive compensation structure.

Compensation Policies and Practices as They Relate to Risk Management

The human resources department conducts an annual risk assessment of our compensation programs. Senior management and our management policy committee reviewed the risk assessment for 2019 and concluded our compensation policies and practices do not create risks which could have a material adverse effect on the company. After review and discussion of the assessment with senior management, the compensation committee concurred with management's assessment.

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 portions of executive compensation based upon the company's total stockholder return in relation to that of 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 primarily to the company's financial and stock performance;

- use of interpolation for annual and long-term incentive awards to avoid payout cliffs;
- negative discretion to adjust any annual incentive award payment downward;
- use of caps on annual incentive awards (maximum of 200% of target for regulated segments and 240% of target for construction materials and services segments) and long-term incentive stock grant awards (maximum of 200% of target);
- ability to clawback incentive payments in the event of a financial restatement;
- use of performance shares and restricted stock units, rather than stock options or stock appreciation rights, as an equity component of incentive compensation;
- use of performance shares for long-term incentive awards with relative total stockholder return, earnings before interest, taxes, depreciation, and amortization (EBITDA) growth, and earnings growth performance measures;
- use of three-year performance periods for performance shares and restricted stock units to discourage short-term risk-taking;
- substantive annual incentive goals measured primarily by earnings, EBITDA, earnings per share criteria, and compound earnings and EBITDA growth, which encourage balanced performance and are important to stockholders;
- use of financial performance metrics that are readily monitored and reviewed;
- regular review of companies in the peer group to ensure appropriateness and industry match;
- stock ownership requirements for the board and for executives participating in the MDU Resources Long-Term Performance-Based Incentive Plan;
- Mandatory holding periods of all company stock awards to executives until stock ownership requirements are achieved and mandatory holding period for 50% of any net after-tax shares of stock earned under long-term incentive awards until the earlier of: (1) the end of the two-year period commencing on the date any stock earned under such award is issued, and (2) the executive's termination of employment; and
- use of independent consultants to assist in establishing pay targets and compensation structure at least biennially.

Components of Compensation

Our executive compensation program is designed to promote sustained long-term profitability and create stockholder value. 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. Pay components and performance measures are considered by the compensation committee as fundamental financial measures of successful company performance and long-term value creation. The components of our 2019 executive compensation included:

Component	Payments	Purpose	How Determined	How it Links to Performance
Base Salary	Assured	Provides sufficient, regularly paid income to attract and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities and reflects the individual role, responsibilities, performance, and experience of each named executive officer and the importance of the role to the company.	Based on recommendation from the CEO for executives other than himself and analysis of peer company and industry compensation information. Base salary for the CEO is determined based on input from the independent compensation consultant.	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 renumeration standpoint.	Annual cash incentives are calculated as a percentage of base salary with payout based on the achievement of performance measures established in advance by the compensation committee.	Annual incentive performance measures are tied to the achievement of financial goals aimed to drive the success of the company and the individual business segments.
Performance Shares	Performance Based At Risk	Provides an opportunity to earn long-term compensation to ensure focus on long-term value creation and the company's strategic objectives and to be competitive from a total renumeration standpoint.	Performance share award opportunities are recommended by the CEO for executives other than himself and approved by the compensation committee. Performance share opportunities for the CEO are determined by the compensation committee with input from the independent compensation consultant. Vesting of the awards is based on the company's achievement of financial measures established by the compensation committee as well as total stockholder return in comparison to the company's peer group over a three-year performance cycle.	Fosters ownership in company stock and aligns the executive's interests with those of stockholders in increasing long-term stockholder value.

Allocation of Total Target Compensation for 2019

Total target compensation consists of base salary plus target annual and long-term incentive compensation. Performance-based 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:

- performance shares align the interests of the named executive officers with those of stockholders by making a significant portion of their target compensation contingent upon results beneficial to stockholders;
- our named executive officers are in positions of authority to drive, and therefore bear high levels of responsibility for, our corporate performance;
- variable compensation helps ensure focus on the goals that are aligned with overall company strategy; and
- incentive compensation is more variable than base salary and dependent upon company performance and the satisfaction of performance objectives.

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 long-term performance. The long-term incentive awards, if earned by achieving established 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. As a result, the compensation committee believes the executive officers, as stockholders, will be motivated to deliver long-term value to all stockholders.

Peer Group

The compensation committee evaluates the company's compensation plan and its performance relative to a group of peer companies in determining overall compensation and the vesting of long-term incentive compensation. The peer group is reviewed annually to assess ongoing relevance and credibility. The companies included in our 2019 peer group were evaluated and recommended by the independent compensation consultant, Meridian Compensation Partners, LLC. In evaluating potential peer companies, the compensation consultant considered companies in the construction and engineering, construction materials, and utility industries. They also sought a group of companies where MDU Resources would rank close to the 50th percentile in terms of revenues and market capitalization. In addition, the consultant considered companies currently listed as peer companies for MDU Resources by proxy advisory firms. The 2019 peer group recommended by the consultant includes eleven companies in regulated energy delivery businesses and ten companies in the construction materials or construction services businesses. At the time of analysis, MDU Resources ranked at the 54th percentile in terms of revenue and at the 41st percentile in terms of market capitalization in comparison to the selected peer group companies. The 2019 peer group reflects MDU Resources' size, mix of current businesses, and complexity and consequently provides an appropriate group for comparative purposes.

The companies included in the 2019 peer group are shown below:

2019 Peer Companies

Regulated Energy Delivery
Alliant Energy Corporation
Ameren Corporation*
Atmos Energy Corporation
Black Hills Corporation
CMS Energy Corporation*
Evergy, Inc.*
NiSource Inc.*
Pinnacle West Capital Corporation*
Portland General Electric Company
Southwest Gas Holdings, Inc.
WEC Energy Group, Inc.*

Construction Materials and Services
Dycom Industries, Inc.*
EMCOR Group, Inc.
Granite Construction Incorporated
Jacobs Engineering Group Inc.*
KBR, Inc.*
Martin Marietta Materials, Inc.
MasTec, Inc.
Quanta Services, Inc.*
Summit Materials, Inc.
Vulcan Materials Company

*These companies were added to the peer group for 2019 to better align with the company's size in revenues and market capitalization.

Companies removed from the previous peer group because they were significantly smaller than the company were ALLETE, Inc., IDACORP, Inc., MYR Group, Inc., Northwest Natural Gas Company, NorthWestern Corporation, Otter Tail Corporation, Spire Inc., U.S. Concrete, Inc., and Vectren Corporation.

2019 Compensation for Our Named Executive Officers

2019 Base Salary and Incentive Targets

At its November 2018 meeting, the compensation committee approved 2019 base salaries for the named executive officers. 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 2019. At its February 2019 meeting, the compensation committee approved the target annual and long-term incentive opportunities for our named executive officers. In determining base salaries, target cash annual incentives, target long-term incentives, and total direct compensation for our named executive officers, the compensation committee received and considered company and individual performance, market and peer data, responsibilities, experience, tenure in position, internal equity, and input and recommendations from the CEO, human resources department, and the independent compensation consultant. The following information relates to each named executive officer's 2019 base salary, target cash annual incentive, target long-term incentive, and target total direct compensation:

David L. Goodin	2019 ($)	Compensation Component as a % of Base Salary
Base Salary	860,000	
Target Annual Incentive Opportunity	860,000	100%
Target Long-Term Performance Share Incentive Opportunity	2,400,000	279%
Target Total Potential Direct Compensation	4,120,000	

The compensation committee considered information provided in the 2018 compensation study showing Mr. Goodin's base salary, total cash compensation, and long-term incentives were below market levels and increased Mr. Goodin's base salary by 4.3%. Mr. Goodin's 2019 annual incentive target remained at 100% of his base salary. The compensation committee, based on recommendations from its compensation consultant, Meridian Compensation Partners, LLC, set Mr. Goodin's long-term incentive target at $2,400,000 which is 279% of his base salary for 2019 compared to 250% in 2018.

Jason L. Vollmer	2019 ($)	Compensation Component as a % of Base Salary
Base Salary	400,000	
Target Annual Incentive Opportunity	300,000	75%
Target Long-Term Performance Share Incentive Opportunity	480,000	120%
Target Total Potential Direct Compensation	1,180,000	

Mr. Vollmer received a 14.3% increase in his base salary from when he was promoted to the CFO position effective September 30, 2017. His 2019 annual incentive target was set at 75% of his base salary; increased from 65% of base salary. No change was made to Mr. Vollmer's long-term incentive as a percentage of his base salary.

David C. Barney	2019 ($)	Compensation Component as a % of Base Salary
Base Salary	468,500	
Target Annual Incentive Opportunity	351,375	75%
Target Long-Term Performance Share Incentive Opportunity	585,000	125%
Target Total Potential Direct Compensation	1,404,875	

Mr. Barney received a 3.0% increase in base salary for 2019. The compensation committee maintained Mr. Barney's target annual incentive opportunity at 75% of his base salary but increased his long-term incentive target to $585,000 or approximately 125% of his base salary, compared to 90% of his base salary in 2018.

Jeffrey S. Thiede	2019 ($)	Compensation Component as a % of Base Salary
Base Salary	468,500	
Target Annual Incentive Opportunity	351,375	75%
Target Long-Term Performance Share Incentive Opportunity	585,000	125%
Target Total Potential Direct Compensation	1,404,875	

Mr. Thiede received a 3.0% increase in his base salary for 2019. The compensation committee maintained Mr. Thiede's target annual incentive opportunity at 75% of base salary but increased his long-term incentive target to $585,000 or approximately 125% of his base salary, compared to 90% of his base salary in 2018.

Nicole A. Kivisto	2019 ($)	Compensation Component as a % of Base Salary
Base Salary	455,000	
Target Annual Incentive Opportunity	341,250	75%
Target Long-Term Performance Share Incentive Opportunity	585,000	129%
Target Total Potential Direct Compensation	1,381,250	

Ms. Kivisto received a base salary increase of 5.8% for 2019. The compensation committee increased her annual incentive target to 75% of her base salary; increased from 65% of base salary in 2018. Her long-term incentive target was increased to $585,000 or approximately 129% of her base salary, compared to 90% of base salary in 2018.

Annual Incentives

Annual incentive awards are determined for business segment executives by the achievement of financial performance measures specific to each business segment plus a performance measure tied to overall company earnings per share. For corporate executives, annual incentive awards are determined as the sum of the weighted percentage award payouts for each business segment with the weighting based upon the business segment's invested capital relative to the company's total 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 selected objective financial performance measures to ensure that compensation to the executives reflects the success of their respective business segments and the company. The annual incentive performance measures for each business segment president include a corporate earnings per share performance measure representing 20% of the target award opportunity and a business segment financial performance measure representing 80% of the target award opportunity. In February 2019, the compensation committee set performance targets that it believed were rigorous based on the company's capital and business plans, prior year results, and anticipated future market conditions. To incentivize executives to make decisions that have long-term positive impact, even at the expense of short-term results, and to prevent one-time gains and losses from having an undue impact on incentive payments, the compensation committee designed its annual incentive measures to allow for adjustments for certain unplanned events that impact our performance targets but are not indicative of underlying business performance. The following annual incentive performance measures for 2019 were adopted by the compensation committee for the business segment presidents (exclusive of the MDU Resources Group, Inc. corporate executive officers) at its February 2019 meeting:

Measure	Applies to	Purpose	Measurement	Target	Weight	How Target was Selected
MDU Resources Diluted Adjusted Earnings per Share (EPS)	All Business Segment Presidents	EPS is a generally accepted accounting principle (GAAP) measurement and is a key driver of stockholder return. This is the basis on which we provide annual performance expectations and consistent with how we report results to the financial community. 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 earnings/losses from any operations discontinued after December 31, 2018, and adjustments approved by the compensation committee to remove: - the effect on earnings at the company level of intersegment earnings eliminations; - the negative effect on earnings from asset sales/dispositions/ retirements; - the effect on earnings from withdrawal liabilities relating to multiemployer pension plans; - the effect on earnings from costs incurred for acquisitions and mergers; and - the effect on earnings from unanticipated changes and interpretations of tax law.	$1.45	20%	Target reflects 2019 financial goal to achieve an estimated return on invested capital of 7.4%. The 2019 target is 10 cents more than the 2018 target and 7 cents more than 2018 actual EPS before discontinued operations (diluted).
Business Segment Earnings	Electric and Natural Gas Distribution Segments President	Provides a measure of financial performance and an incentive to drive business results. Regulated entities are valued based on earnings potential and rate base.	GAAP business segment earnings before discontinued operations plus earnings/losses from any operations discontinued after December 31, 2018, and adjustments approved by the compensation committee to remove: - the negative effect on earnings from asset sales/dispositions/ retirements; - the effect on earnings from transaction costs incurred for acquisitions or mergers; and - the effect on earnings from unanticipated changes and interpretations of tax law.	$91.9 million	80%	Target reflects the 2019 financial goal for the business segment. The 2019 target is 8.5% above 2018 actual results reflecting continued investment in infrastructure and revenue recovery from completed and pending rate cases.
	Pipeline and Midstream Segment President			$27.4 million	80%	Target reflects the 2019 financial goal of the business segment. The 2019 target is 14.2% above the 2018 actual results adjusted for the effects of the Tax Cuts and Jobs Act. The increase reflects anticipated revenue recovery from rate case and investment in completed projects.
Business Segment Earnings Before Interest, Tax, Depreciation, and Amortization (EBITDA)	Construction Materials and Contracting Segment President	Provides a measure of financial performance common to the industries in which these segments operate. Focusing on EBITDA encourages growth by excluding the impact of decisions regarding interest, taxes, and depreciation amortization made during the acquisition process.	EBITDA from continuing operations adjusted plus EBITDA from any operations discontinued after December 31, 2018, and adjustments approved by the compensation committee to remove: - the negative effect on earnings from asset sales/dispositions/ retirements; - the effect on earnings from withdrawal liabilities relating to multiemployer plans, and - the effect on earnings from costs incurred for acquisitions or mergers.	$224.9 million	80%	Target reflects the 2019 financial goal of the business segment and is 12.7% above the actual 2018 EBITDA results. The increase reflects acquisitions completed in 2018 and backlog at 2018 year-end.
	Construction Services Segment President			$105.5 million	80%	Target reflects the 2019 financial goal of the business segment and is 1.8% above the actual 2018 EBITDA results reflecting backlog at 2018 year-end and anticipated organic and acquisition growth but offset by a return to more normal equipment sales and rental results.

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. Achievement of 100% of the target performance measure results in a payout of 100% of the target award opportunity. Achievement of an established threshold is required to receive partial payment of the target award opportunity. Results achieved below the established threshold result in no payout. The threshold and maximum performance as well as the associated payout opportunity are depicted in the following chart:

		Threshold		Maximum	
Measure	Weighting	% of Target	Payout %	% of Target	Payout %
MDU Resources Diluted Adjusted EPS	20%	85%	25%	115%	200%
Electric and Natural Gas Distribution Earnings	80%	90%	50%	110%	200%
Pipeline and Midstream Earnings	80%	85%	25%	115%	200%
Construction Materials and Contracting EBITDA	80%	75%	25%	115%	250%
Construction Services EBITDA	80%	65%	25%	115%	250%

Results achieved between payout levels are calculated using linear interpolation.

2019 Annual Incentive Results

The 2019 performance measure results, percent of target achieved based on those results, and the associated payout percentages reflect the company's excellent 2019 financial performance and are presented below:

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	$1.69	116.6%	200.0%	20%	40.0%
Electric and Natural Gas Distribution	Earnings	$94.3 million	102.6%	125.9%	80%	100.7%
Pipeline and Midstream	Earnings	$29.6 million	108.2%	154.7%	80%	123.8%
Construction Materials and Contracting	EBITDA	$259.0 million	115.1%	250.0%	80%	200.0%
Construction Services	EBITDA	$145.3 million	137.8%	250.0%	80%	200.0%

For our corporate named executive officers, namely Messrs. Goodin and Vollmer, the payout of the annual cash incentives is based 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 2019 annual cash incentives were earned at 163.2% 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 Payout	Column B Percentage of Average Invested Capital	Column A x Column B
Electric and Natural Gas Distribution	140.7%	56.9%	80.1%
Pipeline and Midstream	163.8%	8.7%	14.3%
Construction Materials and Contracting[1]	200.0%	25.3%	50.6%
Construction Services[1]	200.0%	9.1%	18.2%
Total Payout Percentage			163.2%

[1] For purposes of calculating the incentive awards for Messrs. Goodin and Vollmer, the award payouts associated with the construction materials and contracting and construction services segments were limited to 200%, which resulted in a weighted award payout of 200% versus 240% for the construction materials and contracting and construction services business segment presidents.

Based on the achievement of the performance targets, the named executive officers received the following 2019 annual incentive compensation:

Name	Target Annual Incentive ($)	Annual Incentive Earned Payout as a % of Target (%)	Annual Incentive Earned Amount ($)
David L. Goodin	860,000	163.2	1,403,520
Jason L. Vollmer	300,000	163.2	489,600
David C. Barney	351,375	240.0	843,300
Jeffrey S. Thiede	351,375	240.0	843,300
Nicole A. Kivisto	341,250	140.7	480,139

Long-Term Incentives

All our named executive officers participated in the 2019 long-term incentive plan which aligns long-term compensation with the achievement of pre-determined financial goals. Long-term incentive compensation comprised 58.2% of the CEO's 2019 total target direct compensation and 41.6% of the average of the other named executive officer's target total direct compensation. Stock earned under long-term incentive compensation is subject to our stock retention requirements. 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.

Grant of 2019-2021 Long-Term Performance Share Awards

For 2019, the compensation committee approved performance share awards which may vest at the end of a three-year period between 0% and 200% based on the achievement of three performance measures:

- Total stockholder return relative to that of the peer group companies was selected as the measure for 50% of the award vesting to align the award with the company's performance relative to our peers;
- Compound annual growth rate in EBITDA from continuing operations was selected as the measure for 25% of the award vesting to encourage strategic growth and focuses on controllable costs; and
- Compound annual growth rate in earnings from continuing operations was selected as the measure for 25% of the award vesting to encourage quality earnings and continued growth of the company.

For the awards made in 2019, earnings used to calculate EBITDA growth may be adjusted, as such adjustments are approved by the compensation committee, to remove:

- the effect on earnings from leases/impairments on asset sales/dispositions/retirements;
- the effect on earnings from withdrawal liabilities relating to multiemployer pension plans; and
- the effect on earnings from costs incurred for acquisitions or mergers.

Earnings used to calculate earnings growth from continuing operations for the 2019 awards may be adjusted, as approved by the compensation committee, to remove the effects on earnings as noted above for the calculation of EBITDA growth plus any effect on earnings from unanticipated tax law changes.

Vesting of shares and associated dividend equivalents is predicated on achievement of an established threshold associated with each performance measure. To safeguard the confidentiality of our long-term outlook on projected performance outcomes, we do not disclose actual performance targets until the performance period is completed. Achievement of the threshold of the performance measure results in vesting of 20% of the associated portion of the performance share award. Actual results of the performance measure achieved below the threshold lead to zero vesting of the associated portion of the performance share award. Maximum performance measure levels have also been established for each performance measure and result in vesting of 200% of the associated portion of the performance share award. Thresholds and maximum payouts as a percentage of target performance for the 2019 measures are:

The Company's Peer TSR Percentile Rank	The Company's Earnings and EBITDA Growth Rate as a Percentage of Target	Vesting Percentage of Award Target
75th or higher	153.85% or higher	200%
50th	Target	100%
25th	46.15%	20%
Less than 25th	Less than 46.15%	0%

Vesting for percentile ranks falling between the intervals is interpolated.

On February 14, 2019, for the 2019-2021 performance period, the compensation committee determined the target number of performance shares for each named executive officer by dividing a selected target long-term award amount by the average of the closing prices of our stock from January 1 through January 22, 2019, which was $24.29 per share. Based on this price, the compensation committee awarded the following target performance share opportunities to the named executive officers:

Name	Base Salary ($)	Target Long-Term Performance Share Incentive % of Base Salary (%)	Long-Term Performance Share Incentive Target ($)	Performance Share Opportunities (#)
David L. Goodin	860,000	279	2,400,000	98,806
Jason L. Vollmer	400,000	120	480,000	19,761
David C. Barney	468,500	125	585,000	24,083
Jeffrey S. Thiede	468,500	125	585,000	24,083
Nicole A. Kivisto	455,000	129	585,000	24,083

Vesting of 2017-2019 Performance Share Awards

For the 2017-2019 performance period, the long-term incentive program consisted solely of performance shares. The performance criteria used for the 2017-2019 performance period was total stockholder return as a percentile of the total stockholder return for our peer companies over the three-year performance period.

Our total stockholder return ranking over the performance period was at the 26th percentile which resulted in vesting at 23% of the target performance shares and dividend equivalents. The named executive officers received the following long-term compensation for the 2017-2019 performance period:

Name	Target Performance Shares (#)	Performance Shares Vested (#)	Dividend Equivalents ($)
David L. Goodin	61,890	14,234	33,948
Jason L. Vollmer	3,912	899	2,144
David C. Barney	13,338	3,067	7,315
Jeffrey S. Thiede	13,670	3,144	7,498
Nicole A. Kivisto	11,804	2,714	6,473

Stock Retention Requirement

The named executive officers must retain 50% of the net after-tax shares vested pursuant to the long-term incentive awards for the earlier of two years from the date the vested shares are issued or the executive's termination of employment. The executive officer is also required to retain share awards 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 2019 which are described below:

Plans	David L. Goodin	Jason L. Vollmer	David C. Barney	Jeffrey S. Thiede	Nicole A. Kivisto
401(k) Retirement Plan	Yes	Yes	Yes	Yes	Yes
Pension Plans	Yes	Yes	No	No	Yes
Supplemental Income Security Plan	Yes	No	Yes	No	Yes
Nonqualified Defined Contribution Plan	No	Yes	Yes	Yes	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% depending on 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 employees 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 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, 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 ensure compliance with 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 2019."

Supplemental Income Security Plan

We offered 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 2019." Named executive officers participating in the SISP are Messrs. Goodin and Barney and Ms. Kivisto.

The following table reflects our named executive officers' SISP benefits as of December 31, 2019:

	SISP Benefits	
Name	Annual Death Benefit ($)	Annual Retirement Benefit ($)
David L. Goodin	552,960	276,480
Jason L. Vollmer	n/a	n/a
David C. Barney	262,464	131,232
Jeffrey S. Thiede	n/a	n/a
Nicole A. Kivisto	108,000	54,000

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, annually determines which employees will participate in the NQDCP and the amount of contributions for each participant. 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 2019."

For 2019, the compensation committee selected and approved contributions of $40,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. The contributions awarded to Messrs. Vollmer, Barney, and Thiede represent 10.00%, 32.02%, and 21.34% 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. The federal Tax Cuts and Jobs Act (Tax Reform), signed into law in December 2017, 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 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 the performance-based exception for deductibility for purposes of Section 162(m). As a result of 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 believes the tax deduction limitation should not compromise its responsibility to design and maintain a compensation program that will attract and retain the executive talent necessary to successfully execute the company's strategy.

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.

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 beneficially 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[1]	Ownership Requirement Must Be Met By:
David L. Goodin	4X	9.7	01/01/2018
Jason L. Vollmer	3X	0.9	01/01/2023
David C. Barney	3X	2.9	01/01/2019
Jeffrey S. Thiede	3X	3.0	01/01/2019
Nicole A. Kivisto	3X	4.1	01/01/2020

[1] Includes performance stock awards earned net of taxes for the 2017-2019 performance period.

Mr. Barney is required to retain all stock vesting through the Long-Term Performance-Based Incentive Plan, net of taxes, until the stock ownership requirement is met.

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 2019, the interest rate for deferrals was 4.4% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for "A" and "Baa" 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 an associated level of risk to the executives.

Clawback

In February 2016, we amended our Long-Term Performance-Based 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 is primarily responsible for reviewing, approving, and overseeing the company's compensation plans and practices and works with management and the committee's independent compensation consultant to develop the company executive compensation programs. 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.

John K. Wilson, Chair
Thomas Everist
Karen B. Fagg
Patricia L. Moss

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table for 2019

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards ($) (e)[1]	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	2019	860,000	3,029,392	1,403,520	735,366	116,077	6,144,355
President and CEO	2018	824,460	2,433,437	807,971	16,503	72,884 [4]	4,155,255
	2017	792,750	1,504,546	1,377,007	342,727	40,971	4,058,001
Jason L. Vollmer	2019	400,000	605,877	489,600	8,455	86,049	1,589,981
Vice President, CFO and	2018	350,000	495,840	222,950	—	69,589 [4]	1,138,379
Treasurer	2017	256,625	95,101	230,988	3,681	48,156	634,551
David C. Barney	2019	468,500	738,389	843,300	174,117	201,771	2,426,077
President and CEO of	2018	455,000	958,410	384,589	—	251,255 [4]	2,049,254
Knife River Corporation	2017	427,140	324,247	483,736	93,786	173,331	1,502,240
Jeffrey S. Thiede	2019	468,500	738,389	843,300	—	151,751	2,201,940
President and CEO of	2018	455,000	958,410	437,141	—	140,925 [4]	1,991,476
MDU Construction	2017	437,750	332,318	743,629	—	123,163	1,636,860
Services Group, Inc.							
Nicole A. Kivisto	2019	455,000	738,389	480,139	243,761	54,763	1,972,052
President and CEO of	2018	430,000	609,197	225,277	210	42,302 [4]	1,306,986
Montana-Dakota Utilities Co.	2017	378,000	286,955	433,906	96,931	33,049	1,228,841

[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 as described in Note 13 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2019. For 2019, the aggregate grant date fair value of outstanding performance share award opportunities assuming the highest level of payout would be as follows:

Name	Aggregate grant date fair value at highest payout ($)
David L. Goodin	6,058,784
Jason L. Vollmer	1,211,753
David C. Barney	1,476,778
Jeffrey S. Thiede	1,476,778
Nicole A. Kivisto	1,476,778

[2] Amounts shown for 2019 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, 2019.

Name	Accumulated Pension Change ($)	Above Market Interest ($)
David L. Goodin	722,199	13,167
Jason L. Vollmer	8,455	—
David C. Barney	174,117	—
Jeffrey S. Thiede	—	—
Nicole A. Kivisto	243,631	130

[3] All Other Compensation is comprised of:

Name	401(k) Plan ($)[a]	Nonqualified Defined Contribution Plan ($)	Life Insurance Premium ($)	Matching Charitable Contributions ($)	Dividend Equivalents ($)[b]	Total ($)
David L. Goodin	40,600	—	621	2,620	72,236	116,077
Jason L. Vollmer	28,000	40,000	497	2,985	14,567	86,049
David C. Barney	22,400	150,000	582	1,200	27,589	201,771
Jeffrey S. Thiede	22,400	100,000	582	1,180	27,589	151,751
Nicole A. Kivisto	33,600	—	565	2,780	17,818	54,763

[a] Represents company contributions to the 401(k) plan, which includes matching contributions and retirement contributions associated with the freeze of the pension plans at December 31, 2009.

[b] Represents accrued dividend equivalents on the 2019-2021 and 2018-2020 performance share awards at target and restricted stock units awarded to Mr. Barney and Mr. Thiede in 2018.

[4] 2018 All Other Compensation has been updated to include dividend equivalents on the 2018-2020 performance share awards at target for all named executive officers and restricted stock unit awards awarded to Mr. Barney and Mr. Thiede in 2018 which were inadvertently omitted in the Summary Compensation Table for 2018.

Grants of Plan-Based Awards in 2019

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards				
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units # (i)	Grant Date Fair Value of Stock and Option Awards ($) (l)
David L. Goodin	2/14/2019 [1]	313,097	860,000	1,720,000					
	2/14/2019 [2]				19,761	98,806	197,612		3,029,392
Jason L. Vollmer	2/14/2019 [1]	109,220	300,000	600,000					
	2/14/2019 [2]				3,952	19,761	39,522		605,877
David C. Barney	2/14/2019 [1]	87,844	351,375	843,300					
	2/14/2019 [2]				4,816	24,083	48,166		738,389
Jeffrey S. Thiede	2/14/2019 [1]	87,844	351,375	843,300					
	2/14/2019 [2]				4,816	24,083	48,166		738,389
Nicole A. Kivisto	2/14/2019 [1]	153,563	341,250	682,500					
	2/14/2019 [2]				4,816	24,083	48,166		738,389

[1] Annual incentive for 2019 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

[2] Performance shares for the 2019-2021 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2019 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 14, 2019. 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 2019 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%.

All our named executive officers 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 or after age 65 remain 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 in years of unusually adverse or favorable external conditions or other unforeseen significant factors beyond the control of management, the compensation committee 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 2019 incentive plan performance measures and results, see the "Annual Incentives" section in the "Compensation Discussion and Analysis."

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 14, 2019. 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 the achievement of the performance measures associated with our 2019-2021 performance period, executives will receive from 0% to 200% of the target awards in February 2022. 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 2022 at the same time as the performance share awards are settled.

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 $40,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. For further information, see the section entitled "Nonqualified Deferred Compensation for 2019."

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	860,000	—	6,144,355	14.0%
Jason L. Vollmer	400,000	—	1,589,981	25.2%
David C. Barney	468,500	—	2,426,077	19.3%
Jeffrey S. Thiede	468,500	—	2,201,940	21.3%
Nicole A. Kivisto	455,000	—	1,972,052	23.1%

Outstanding Equity Awards at Fiscal Year-End 2019

Name (a)	Stock Awards: Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[1]	Stock Awards: Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[2]
David L. Goodin	416,422	12,371,898
Jason L. Vollmer	75,408	2,240,372
David C. Barney	114,491	3,401,528
Jeffrey S. Thiede	114,823	3,411,391
Nicole A. Kivisto	99,254	2,948,836

1 Below is a breakdown by year of the outstanding performance share plan awards:

	2017 Award	2018 Award	2019 Award	
Performance Period End	12/31/2019	12/31/2020	12/31/2021	Total
David L. Goodin	61,890	156,920	197,612	416,422
Jason L. Vollmer	3,912	31,974	39,522	75,408
David C. Barney	13,338	52,987	48,166	114,491
Jeffrey S. Thiede	13,670	52,987	48,166	114,823
Nicole A. Kivisto	11,804	39,284	48,166	99,254

Shares for the 2017 award are shown at the target level (100%) based on results for the 2017-2019 performance cycle between threshold and target.

Shares for the 2018 award are shown at the maximum level (200%) based on results for the first two years of the 2018-2020 performance cycle above target. The number of shares under the 2018 award also includes 11,419 time-vesting restricted stock units granted to Messrs. Barney and Thiede.

Shares for the 2019 award are shown at the maximum level (200%) based on results for the first year of the 2019-2021 performance cycle above target.

2 Value based on the number of performance shares and restricted stock units reflected in column (i) multiplied by $29.71, the year-end per share closing stock price for 2019.

While for purposes of the Outstanding Equity Awards at Fiscal Year-End 2019 Table, the number of shares and value shown for the 2017-2019 performance cycle is at 100% of target, the actual results for the performance period certified by the compensation committee and settled on February 13, 2020, was 23% of target. For further information, see the "Long-Term Incentives" section of the "Compensation Discussion and Analysis."

Option Exercises and Stock Vested During 2019

Name (a)	Stock Awards: Number of Shares Acquired on Vesting (#) (d)[1]	Stock Awards: Value Realized on Vesting ($) (e)[2]
David L. Goodin	138,269	3,951,037
Jason L. Vollmer	6,673	190,681
David C. Barney	26,488	756,895
Jeffrey S. Thiede	27,673	790,756
Nicole A. Kivisto	23,441	669,827

[1] Reflects performance shares for the 2016-2018 performance period ended December 31, 2018, which were settled February 14, 2019.

[2] Reflects the value of vested performance shares based on the closing stock price of $26.25 per share on February 14, 2019, and the dividend equivalents paid on the vested shares.

Pension Benefits for 2019

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)[1]	Present Value of Accumulated Benefit ($) (d)
David L. Goodin	Pension	26	1,372,606
	Basic SISP [2]	10	2,836,360
	Excess SISP [3]	26	42,331
Jason L. Vollmer	Pension	4	29,312
	Basic SISP [3]	n/a	—
	Excess SISP [3]	n/a	—
David C. Barney	Pension [3]	n/a	—
	Basic SISP [2]	10	1,623,404
	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	302,478
	Basic SISP [2]	9	586,981
	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. Messrs. Vollmer and Thiede do 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, 2019, calculated using:

- a 2.71% discount rate for the Basic SISP and Excess SISP;
- a 2.93% discount rate for the pension plan;
- the Society of Actuaries PRi-2012 Total Dataset Mortality with Scale MP-2019 (post commencement only); 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 Excess SISP and age 65 for Basic 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 nonqualified defined benefit 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.

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 for 2019

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 by the compensation committee. The interest rate in effect for 2019 was 4.4% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for "A" and "Baa" 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 and after 2017 vest rateably over a three-year period with one-third vesting after the first year, an additional one-third after the second year, and the final one-third 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 for the hypothetical investments selected by the participants. 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	403,986	—	82,592	—	1,985,235 [1]
Jason L. Vollmer	—	40,000	27,426	—	123,675 [2]
David C. Barney	—	150,000	91,195	—	544,980 [3]
Jeffrey S. Thiede	—	100,000	157,271	—	884,439 [4]
Nicole A. Kivisto	—	—	794	—	18,479

[1] Mr. Goodin deferred 50% of his 2018 annual incentive compensation which was $807,971 as reported in the Summary Compensation Table for 2018.

[2] Mr. Vollmer received $40,000 under the Nonqualified Defined Contribution Plan for 2019. Mr. Vollmer's balance also includes a contribution of $35,000 for 2018 and $22,550 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year, where applicable.

[3] Mr. Barney received $150,000 under the Nonqualified Defined Contribution Plan for 2019. Mr. Barney's balance also includes a contribution of $150,000 for each of 2018 and 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year.

[4] Mr. Thiede received $100,000 under the Nonqualified Defined Contribution Plan for 2019. Mr. Thiede's balance also includes contributions of $100,000 for each of 2018, 2017, and 2016, $150,000 for 2015, $75,000 for 2014, and $33,000 for 2013. Each of these amounts was 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. The scenarios include:

- Voluntary Termination;
- Not for Cause Termination;
- Death;
- Disability;
- Change of Control with Termination; and
- Change of Control without Termination.

For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2019.

The table excludes compensation and benefits our named executive officers would earn during their employment with us whether or not a termination or change of control event had occurred. The tables also do not include benefits under plans or arrangements generally available to all salaried employees and that do not discriminate in favor of the named executive officers, 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 2019 Table.

Compensation

None of our named executive officers have employment or severance agreements entitling them to their base salary, some multiple of base salary or severance upon termination or change of control. Our 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.

All our named executive officers were granted their 2019 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. The EICP requires participants to remain employed with the company through the service year to be eligible for a payout unless otherwise determined by the compensation committee for named executive officers or employment termination after age 65. As all our scenarios assume a termination or change in control event on December 31st, the named executives officers would be considered employed for the entire performance period; therefore, no amounts are shown for annual incentives in the tables for our named executive officers, 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 occurring on December 31, 2019.

All named executive officers received their performance share awards under the Long-Term Performance-Based Incentive Plan (LTIP). Upon a change of control (with or without termination), performance share awards 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:

- 2017-2019 performance shares would vest based on the achievement of the performance measure for the period ended December 31, 2019, which was 23%;
- 2018-2020 performance shares would be prorated at 24 out of 36 months (2/3) of the performance period and vest based on the actual achievement of the performance measure for the period ended December 31, 2020. For purposes of the Potential Payments upon Termination or Change of Control Table, the vesting is shown at 100%; and
- 2019-2021 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 31, 2019. 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.

Messrs. Barney and Thiede were granted 11,419 restricted stock units in February 2018. The restricted stock units will vest on December 31, 2020, provided that Messrs. Barney and Thiede remain continuously employed by the company through December 31, 2020, except for termination due to death or disability or a change in control as defined in the LTIP. In the case of a voluntary or not for cause termination on December 31, 2019, Messrs Barney and Thiede would forfeit the restricted stock units. In the case of death or disability, the restricted stock units would vest based on the number of full months of employment completed during the grant period to the date of death or disability divided by the total number of months in the grant period. In the case of death or disability occurring on December 31, 2019, two-thirds of Messrs. Barney and Thiede's restricted stock units plus dividend equivalents would vest. In the case of a change of control (with or without termination) occurring on December 31, 2019, the restricted stock units plus dividend equivalents would fully vest.

Benefits and Perquisites

Supplemental Income Security Plan

As described in the "Pension Benefits for 2019" section, the Basic SISP provides a benefit of payments commencing at the latter of retirement or age 65 and payable for 15 years. Of the named executive officers, only Messrs. Goodin, Barney, and Ms. Kivisto participate in the 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 90% vested in her SISP benefit at December 31, 2019. Ms. Kivisto received a benefit level upgrade in 2014, which cliff vests on January 1, 2021. This means that if her employment terminates for any reason other than death before January 1, 2021, her benefit upgrade is forfeited.

Under all scenarios except death and change of control without termination, the payment represents the present value of the vested Basic SISP benefit as of December 31, 2019, using the monthly retirement benefit shown in the table below and a discount rate of 2.71%. In the event of death, Messrs. Goodin, Barney, and Ms. Kivisto's beneficiaries would receive monthly death benefit payments for 15 years. The Potential Payments upon Termination or Change of Control Table shows the present value calculations of the monthly death benefit using the 2.71% discount rate.

	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	5,000 *	10,000 *

* Ms. Kivisto's calculations are based on 90% of the value shown above for voluntary, not for cause and change of control with termination scenarios. The disability scenario allows for two additional years of vesting and is calculated using 100% of the value shown above. Ms. Kivisto's death benefit scenario is calculated using her 2014 benefit upgrade level with a monthly death benefit of $13,144.

Because the plan requires a participant to be no longer actively employed by the company in order to be eligible for payments, we do not show benefits for the change of control without termination scenario.

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 payments 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 2.93%. 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 2.71%, which is considered a reasonable rate for purposes of the calculation.

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:						
Performance Shares	2,090,438	2,090,438	2,090,438	2,090,438	7,443,039	7,443,039
Benefits and Perquisites:						
Basic SISP	2,836,089	2,836,089	—	2,836,089	2,836,089	—
SISP Death Benefits	—	—	6,824,695	—	—	—
Disability Benefits	—	—	—	—	—	—
Total	**4,926,527**	**4,926,527**	**8,915,133**	**4,926,527**	**10,279,128**	**7,443,039**
Jason L. Vollmer						
Compensation:						
Performance Shares	—	—	—	—	1,226,697	1,226,697
Benefits and Perquisites:						
Disability Benefits	—	—	—	965,329	—	—
Total	**—**	**—**	**—**	**965,329**	**1,226,697**	**1,226,697**
David C. Barney						
Compensation:						
Performance Shares	531,221	531,221	531,221	531,221	1,810,097	1,810,097
Restricted Stock Units	—	—	237,875	237,875	356,844	356,844
Benefits and Perquisites:						
Basic SISP	1,608,756	1,608,756	—	1,608,756	1,608,756	—
SISP Death Benefits	—	—	3,239,360	—	—	—
Disability Benefits	—	—	—	280,900	—	—
Total	**2,139,977**	**2,139,977**	**4,008,456**	**2,658,752**	**3,775,697**	**2,166,941**
Jeffrey S. Thiede						
Compensation:						
Performance Shares	533,687	533,687	533,687	533,687	1,820,730	1,820,730
Restricted Stock Units	—	—	237,875	237,875	356,844	356,844
Benefits and Perquisites:						
Disability Benefits	—	—	—	387,175	—	—
Total	**533,687**	**533,687**	**771,562**	**1,158,737**	**2,177,574**	**2,177,574**
Nicole A. Kivisto						
Compensation:						
Performance Shares	—	—	—	—	1,709,044	1,709,044
Benefits and Perquisites:						
Basic SISP	402,102	402,102	—	446,780	402,102	—
SISP Death Benefits	—	—	1,946,697	—	—	—
Disability Benefits	—	—	—	740,621	—	—
Total	**402,102**	**402,102**	**1,946,697**	**1,187,401**	**2,111,146**	**1,709,044**

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 project activity conducted by our businesses. Approximately 51% 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 2019 taxable wage information for all individuals on the company's payroll records as of December 31, 2019, 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 2019 to identify the median employee as it includes substantially all of the compensation for our median employee and provided a reasonably efficient and cost-effective manner for the identification of the median employee. Our median employee is a member of a union and works for a subsidiary of our construction services segment; he does not participate in our pension or 401(k) plan.

Once identified, we categorized the median employee's compensation to correspond to the compensation components as reported in the Summary Compensation Table. For 2019, the total annual compensation of Mr. Goodin as reported in the Summary Compensation Table included in this Proxy Statement was $6,144,355, and the total annual compensation of our median employee was $63,768. Based on this information, the 2019 ratio of annual total compensation of Mr. Goodin to the median employee was 96 to 1.

AUDIT MATTERS

ITEM 3: RATIFICATION OF THE APPOINTMENT OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2020

The audit committee at its February 2020 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2020. 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 2020, 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 2020.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2020 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, 2020, is in the best interests of our company and its stockholders.

In accordance with rules applicable to mandatory partner rotation, Deloitte & Touche LLP's lead engagement partner for our audit was changed in 2017. The audit committee oversees the process for, and ultimately approves, the selection of the lead engagement partner.

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 2019 and 2018:

	2019	2018
Audit Fees [1]	$ 2,919,950	$ 2,657,405
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees [2]	5,000	3,150
Total Fees [3]	$ 2,924,950	$ 2,660,555
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0.2 %	0.1 %

[1] Audit fees for 2019 and 2018 consisted of fees for the annual audit of our consolidated financial statements and internal control over financial reporting, statutory and regulatory audits, reviews of quarterly financial statements, comfort letters in connection with securities offerings, and other filings with the SEC.

[2] All other fees relate to training.

[3] Total fees reported above include out-of-pocket expenses related to the services provided of $310,000 for 2019 and $330,000 for 2018.

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 2019 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, currently David M. Sparby, 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

The audit committee assists the board in fulfilling its oversight responsibilities and serves as a communication link among the board, management, the independent auditors, and the internal auditors. The audit committee (a) assists the board's oversight of (i) the integrity of the company's financial reporting process and system of internal controls, (ii) the company's compliance with legal and regulatory requirements and the code of conduct, (iii) the independent auditors' qualifications and independence, (iv) the performance of the company's internal audit function and independent auditors, and (v) the company's management of risks in the audit committee's areas of responsibility; (b) arranges for the preparation of and approves the report that SEC rules require be included in the company's annual proxy statement; (c) is also responsible for the appointment, compensation, retention, and oversight of the independent auditors including pre-approval of all audit and non-audit services by the independent auditors. The audit committee acts under a written charter which it reviews at least annually and a copy of which is available on our website.

Management has primary responsibility for the company's financial statements and the reporting process, including the systems of internal control over financial reporting. The independent auditors are responsible for performing an independent audit of the company's consolidated financial statements, issuing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, and assessing the effectiveness of the company's internal controls over financial reporting. The audit committee oversees the company's financial reporting process and internal controls on behalf of the board.

In performing its oversight responsibilities in connection with our financial statements for the year ended December 31, 2019, the audit committee:

- reviewed and discussed the audited financial statements with management;
- discussed with the independent auditors the matters required to be discussed by the applicable requirements of the Public Company Accounting Oversight Board and the SEC;
- received the written disclosures and the letter from the independent auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent auditors' communications with the audit committee concerning independence, and discussed with the independent auditors their independence; and
- reviewed and pre-approved the services provided by the independent auditors other than their audit services and considered whether the provision of such other services by our independent auditors is compatible with maintaining their independence.

Based on the review and discussions referred to above, the audit committee recommended to the board of directors, and the board of directors has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2019, for filing with the SEC. The audit committee has appointed Deloitte & Touche LLP as the company's independent auditors for 2020. Stockholder ratifications of this appointment is included as Item 3 in these proxy materials.

David M. Sparby, Chair
Mark A. Hellerstein
Edward A. Ryan
Chenxi Wang

INFORMATION ABOUT THE ANNUAL MEETING

Who Can Vote?

Stockholders of record at the close of business on March 13, 2020, 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 13, 2020, we had 200,522,277 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 27, 2020, we mailed a Notice Regarding the Availability of Proxy Materials (Notice) that contains basic information about our 2020 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 April 2, 2020.

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 2020 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 11, 2020.

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.

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 regarding 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:

- *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.
- *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.
- 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.

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. Abstentions and broker non-votes are counted for purposes of determining whether a quorum is present at the annual meeting.

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 2020.

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 2020	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 12, 2020, 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 $8,500 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.

- **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.
- **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 7, 2020.

Annual Meeting Admission and Guidelines

Admission: All stockholders as of the record date of March 13, 2020, are cordially invited and urged to attend the annual meeting. **You must request an admission ticket 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 13, 2020, 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, 2020. 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 the media or 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.

Annual Meeting Admission and Guidelines (Continued)

Public Health Concerns: We are actively monitoring the public health and travel safety concerns relating to the coronavirus (COVID-19) and the advisories or mandates that federal, state, and local governments and related agencies may issue. In the event it is not possible or advisable to hold our annual meeting as currently planned, we will announce additional or alternative arrangements for the meeting, which may include a change in venue or holding the meeting solely by means of remote communication. Please monitor our company website at https://www.mdu.com for updated information. If you are planning to attend our meeting, please check our website the week of the meeting. As always, we encourage you to vote your shares prior to the annual meeting.

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 2021 Annual Meeting

Stockholder Proposals for Inclusion in Next Year's Proxy Statement. To be included in the proxy materials for our 2021 annual meeting, a stockholder proposal must be received by the corporate secretary no later than November 27, 2020, unless the date of the 2021 annual meeting is more than 30 days before or after May 12, 2021, 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 Exchange Act of 1934.

Director Nominations From Stockholders for Inclusion in Next Year's Proxy Statement. If a stockholder or group of stockholders wishes to nominate one or more director candidates to be included in our proxy statement for the 2021 annual meeting through our proxy access bylaw provision, we must receive proper written notice of the nomination not later than 120 days or earlier than 150 days before the anniversary date that the definitive proxy statement was first released to stockholders in connection with the annual meeting, or between October 28, 2020 and November 27, 2020. In the event that the 2021 annual meeting is more than 30 days before or after May 12, 2021, the notice must be delivered no earlier than the 150th day prior to such meeting and no later than the 120th day prior to such meeting or the 10th day following the date on which public announcement of the meeting date is first made. In addition, the nomination must otherwise comply with the requirements in our bylaws. The requirements of such notice can be found in our bylaws, a copy of which is on our website, at www.mdu.com/governance.

Director Nominations and Other Stockholder Proposals Raised From the Floor at the 2021 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 within 90 to 120 days prior to the anniversary of the most recent annual meeting. Notice of director nominations or stockholder proposals for our 2021 annual meeting must be received between January 12, 2021 and February 11, 2021, 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 www.mdu.com/governance.

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, 2019, 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 27, 2020

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 2019 was 1,036,009 shares.

Common Stock Prices

	High	Low	Close
2019			
First Quarter	$27.19	$23.36	$25.83
Second Quarter	26.64	24.37	25.80
Third Quarter	28.82	25.25	28.19
Fourth Quarter	29.83	27.19	29.71
2018			
First Quarter	$28.23	$24.29	$28.16
Second Quarter	29.28	27.05	28.68
Third Quarter	29.62	25.33	25.69
Fourth Quarter	26.96	22.73	23.84

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.

2020 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 11	March 12	April 1
Second Quarter	June 10	June 11	July 1
Third Quarter	September 9	September 10	October 1
Fourth Quarter	December 9	December 10	January 1, 2021

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT May 12, 2020
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: 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.

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Trading Symbol: MDU
www.mdu.com

MDU
LISTED
NYSE

MDU RESOURCES
GROUP, INC.

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2019

INDEX

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	GAS UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	67,070,587	62,341,032
3	Operating Expenses			
4	Operation Expenses (401)	4-9	45,189,208	42,747,407
5	Maintenance Expenses (402)	4-9	1,534,085	1,738,467
6	Depreciation Expense (403)	10	6,881,592	6,154,978
7	Amortization & Depletion of Utility Plant (404-405)	10	891,397	909,516
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	5,734,175	5,105,787
12	Income Taxes - Federal (409.1)	12	(638,182)	477,754
13	Income Taxes - Other (409.1)	13	(941,388)	(461,582)
14	Provision for Deferred Income Taxes (410.1)	14-21	12,811,911	2,444,547
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	(11,030,657)	(2,356,657)
16	Investment Tax Credit Adjustment - Net (411.4)	22	(10,278)	(9,690)
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)		60,421,863	56,750,527
20	Net Utility Operating Income (Enter Total of line 2 less 19)		6,648,724	5,590,505

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CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - GAS OPERATING REVENUES (ACCOUNT 400)

Line No.	ACCOUNT	OPERATING REVENUES		MCF OF NATURAL GAS SOLD		AVG. NO. OF NAT. GAS CUSTUMERS PER MO.	
		CURRENT YEAR	PREVIOUS YEAR	CURRENT YEAR	PREVIOUS YEAR	CURRENT YEAR	PREVIOUS YEAR
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	$ 37,648,100	$ 35,735,954	4,631,397	4,078,092	65,860	64,137
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 21,011,593	$ 19,735,290	3,192,406	2,836,254	10,144	10,061
5	Large or Industrial	$ 4,009,032	$ 4,064,217	710,667	671,341	161	157
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 62,668,725	$ 59,535,461	8,534,470	7,585,687	76,165	74,355
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 62,668,725	$ 59,535,461	8,534,470	7,585,687	76,165	74,355
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 62,668,725	$ 59,535,461				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 169,984	$ 146,470				
17	489 Revenue from Trans. of Gas of Others	$ 4,432,276	$ 4,125,680				
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	$ 11,000				
22	494 Interdepartmental Rents	$ 42,263	$ 28,749				
23	495 Other Gas Revenues	$ 13,492	$ 51,692				
24	TOTAL Other Operating Revenues	$ 4,670,015	$ 4,363,591				
25	TOTAL Gas Operating Revenues	$ 67,338,740	$ 63,899,052				
26	(Less) 496 Provision for Rate Refunds	$ (268,153)	$ (1,558,020)				
27	TOTAL Gas Operating Revenues Net of Provision for Refunds						
28	Dist. Type Sales by States (*Incl. Main Line Sales to Residential and Commercial Customers)*	$ 58,659,693		7,823,803			
29	Main Line Industrial Sales *(Incl. Main Line Sales to Public Authorities)*	$ 4,009,032		710,667			
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))*	$ 62,668,725		8,534,470			

NOTES:

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CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

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

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

LINE NO.	NAME OF LESSEE OR DEPARTMENT (Designate associated companies) (a)	DESCRIPTION OF PROPERTY (b)	AMOUNT OF REVENUE FOR YEAR NATURAL GAS PROPERTY (c)	MANUFACTURED GAS PROPERTY (d)
	Account 493			
	Stone Bros., Inc.	Northern portion of parking lot at the Hermiston office for a latte stand.	$ 12,000	
			$ -	
			$ -	
	Total Account 493		$ 12,000	

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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

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

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
	B2. Products Extraction (Con't)		
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Reg. Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	Total Maintenance (Enter Total of lines 49 thru 56)	0	0
58	Total Products Extraction (Enter Total of lines 47 and 57)	0	0
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	Total Exploration & Development (Enter Total of lines 61 thru 64)	0	0
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases	0	0
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
69	801 Natural Gas Field Line Purchases	0	0
70	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
71	803 Natural Gas Transmission Line Purchases	0	0
72	804 Natural Gas City Gate Purchases	38,267,373	32,942,897
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	(7,645,455)	(3,808,349)
76	805.2 Incremental Gas Cost Adjustments	0	0
77	Total Purchased Gas (Enter Total of lines 67 to 75)	30,621,918	29,134,548
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	882,304	506,266
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	(15,089)	(10,870)
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(15,089)	(10,870)
95	813 Other Gas Supply Expenses	110,977	88,245
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	31,600,110	29,718,189
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	31,600,110	29,718,189

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
98	2. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	Total Operation (Enter Total of lines 101 thru 113)	0	0
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	Total Maintenance (Enter Total of lines 116 thru 123)	0	0
125	Total Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	Total Operation (Enter Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures and Improvements	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	Total Maintenance (Enter Total of lines 136 thru 144)	0	0
146	Total Other Storage Expenses (Enter Total of lines 134 and 145)	0	0

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

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulation Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(Less) 845.5 Wharfage Receipts - Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	Total Operation (Enter Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	Total Maintenance (Enter Total of lines 167 thru 174)	0	0
176	Total Liquefied Nat Gas Terminaling & Process Exp (Lines 165 & 175)	0	0
177	Total Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	Total Operation (Enter Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Reg. Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	Total Maintenance (Enter Total of lines 193 thru 199)	0	0
201	Total Transmission Expenses (Enter Total of lines 191 and 200)	0	0

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2019**

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

LINE NO.	ACCOUNT (a)	CUURENT YEAR (b)	PREVIOUS YEAR (c)
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	857,539	826,122
205	871 Distribution Load Dispatching	93,055	85,199
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,392,379	1,282,991
209	875 Measuring and Regulating Station Expenses - General	167,374	176,642
210	876 Measuring and Regulating Station Expenses - Industrial	30,552	38,171
211	877 Measuring & Regulating Station Exp - City Gate Check Station	0	0
212	878 Meter and House Regulator Expenses	212,192	231,859
213	879 Customer Installations Expenses	221,585	241,652
214	880 Other Expenses	2,127,507	1,884,697
215	881 Rents	25,710	28,789
216	Total Operation (Enter Total of lines 204 thru 215)	5,127,893	4,796,122
217	Maintenance		
218	885 Maintenance Supervision and Engineering	241,936	221,877
219	886 Maintenance of Structures and Improvements	0	441
220	887 Maintenance of Mains	259,335	415,071
221	888 Maintenance of Compressor Station Equipment	21	227
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	64,133	69,974
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	18,132	5,266
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	0
225	892 Maintenance of Services	293,453	408,632
226	893 Maintenance of Meters and House Regulators	252,112	251,250
227	894 Maintenance of Other Equipment	394,676	357,562
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,523,798	1,730,300
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	6,651,691	6,526,422
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	36,248	35,776
233	902 Meter Reading Expenses	225,211	219,001
234	903 Customer Records and Collection Expenses	1,397,978	1,404,414
235	904 Uncollectible Accounts	215,040	171,038
236	905 Miscellaneous Customer Accounts Expenses	32,728	2
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,907,205	1,830,231
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	166,899	208,213
242	909 Informational and Instructional Expenses	51,851	2,983
243	910 Miscellaneous Customer Service and Informational Expenses	89,173	86,177
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	307,923	297,373
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	1,051	0
249	913 Advertising Expenses	1,023	1,293
250	916 Miscellaneous Sales Expenses	0	0
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	2,074	1,293

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	2,186,116	1,882,113
255	921 Office Supplies and Expenses	1,125,495	1,057,859
256	(Less) 922 Administrative Expenses Transferred - Cr.	(104,567)	(101,231)
257	923 Outside Services Employed	188,361	577,828
258	924 Property Insurance	27,405	20,620
259	925 Injuries and Damages	334,701	465,943
260	926 Employee Pensions and Benefits	1,753,413	1,492,230
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	100,603	0
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	9,597	8,194
265	930.2 Miscellaneous General Expenses	250,751	297,496
266	931 Rents	372,128	403,147
267	Total Operation (Enter Total lines 254 thru 266)	6,244,003	6,104,199
268	Maintenance		
269	935 Maintenance of General Plant	10,287	8,167
270	Total Administrative and General Exp (Total of lines 267 and 269)	6,254,290	6,112,366
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	46,723,293	44,485,874

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	31,600,110	0	31,600,110
280	Total Production	31,600,110	0	31,600,110
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	5,127,893	1,523,798	6,651,691
286	Customer Accounts Expenses	1,907,205	0	1,907,205
287	Customer Service and Informational Expenses	307,923	0	307,923
288	Sales Expenses	2,074	0	2,074
289	Admin and General Expenses	6,244,003	10,287	6,254,290
290	Total Gas O. & M. Expenses	45,189,208	1,534,085	46,723,293

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURALGAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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			891,397			891,397
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	6,396,479					6,396,479
10	General Plant	371,940					371,940
11	Common Plant - Gas						-
12							
13							
14							
15							
16							
17							
18							
19	**TOTAL**	**6,881,592**	**-**	**891,397**	**-**	**-**	**7,772,989**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,829,815
2	Payroll Taxes	605,206
3	Oregon PUC Regulatory Fee	187,024
4	Oregon Department of Energy Fee	78,672
5	City Franchise Taxes	2,996,281
6	Miscellaneous Taxes	37,177
	TOTAL (Must agree with page 1, line 11)	**5,734,175**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

Line No.	PARTICULARTS (Details) (a)				Amount (b)
1	Gas Operating Revenues				157,740,604
2	Operations and Maintenance Expenses				(68,089,710)
3	Taxes, Other than Income				(30,542,472)
4	State Income (Excise) Tax				794,015
5	Interest				(15,173,527)
6	Other Income				5,250,296
7	Federal Income Tax Depreciation				(38,551,269)
8	Other Additions (Subtractions) to Derive Taxable Income				
9	AFUDC-Debt/Equity				(649,190)
10	Capitalized Tax Interest				1,008,398
11	CIAC				1,031,570
12	Customer Advances				(92,058)
13	Loss on Disposal of Assets				(3,231,959)
14	Amort of loss on reacquired debt				40,971
15	Bad Debts				52,433
16	Legal Reserve				(29,318)
17	Pension & Post Retirement				61,873
18	Prepaid Expenses				(110,856)
19	Reserved Revenue				(348,812)
20	SISP/SERP				(40,723)
21	STIP Payroll Taxes				771,124
22	Vacation Pay				(46,306)
23	50% of Meals & Entertainment				162,778
24	Other Permanent Differences				12,995
25	Lobbying Expenses				306,254
26	Manufactured Gas Plant Cleanup				(518,600)
27	MAOP Deferred Costs				(1,905,558)
28	Conservation Programs				(495,644)
29	Purchased Gas Adjustment				(47,723,076)
30	UNICAP				1,410
31	401k Dividends				(209,490)
32	SISP/SERP Premium & CSV				(1,705,005)
33	Performance Shares				(526,635)
34	Federal Tax Net Income				(42,755,487)
35	Show Computation of Tax:				
36	Federal Tax Rate				21%
37	Estimated Federal Tax				(8,978,652)
38	Adjustments to Estimated Federal Tax				
39	Difference between 12/31/18 accrual and tax return				(1,843,703)
40	R&D credit				(145,000)
41	FIN 48 Adjustment				29,000
42	Provision for Current Federal Income Tax			409.1	(10,938,355)
43					
44					
45	Allocated to:	409.1	409.2		Total
46	Washington	(10,887,316)	616,283		(10,271,033)
47	Oregon	(638,182)	(29,140)		(667,322)
48	Total	(11,525,498)	587,143		(10,938,355)
49					
50					
51					
52					
53					
54					
55					

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, 2019**

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

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

Line No.	Particularts (Details) (a)			Amount (b)
1	Gas Operating Revenues			157,740,604
2	Operations and Maintenance Expenses			(68,089,710)
3	Taxes, Other than Income			(30,542,472)
4	State Income (Excise) Tax			
5	Interest			(15,173,527)
6	Other Income			5,250,296
7	Federal Income Tax Depreciation			(38,551,269)
8	Other Additions (Subtractions) to Derive Taxable Income			
9	AFUDC-Debt/Equity			(649,190)
10	Capitalized Tax Interest			1,008,398
11	CIAC			1,031,570
12	Customer Advances			(92,058)
13	Loss on Disposal of Assets			(3,231,959)
14	Amort of loss on reacquired debt			40,971
15	Bad Debts			52,433
16	Legal Reserve			(29,318)
17	Pension & Post Retirement			61,873
18	Prepaid Expenses			(110,856)
19	Reserved Revenue			(348,812)
20	SISP/SERP			(40,723)
21	STIP Payroll Taxes			771,124
22	Vacation Pay			(46,306)
23	50% of Meals & Entertainment			162,778
24	Other Permanent Differences			12,995
25	Lobbying Expenses			306,254
26	Manufactured Gas Plant Cleanup			(518,600)
27	MAOP Deferred Costs			(1,905,558)
28	Conservation Programs			(495,644)
29	Purchased Gas Adjustment			(47,723,076)
30	UNICAP			1,410
31	401k Dividends			(209,490)
32	SISP/SERP Premium & CSV			(1,705,005)
33	Performance Shares			(526,635)
34	OR Bonus Depreciation			(443,431)
35	Federal Tax Net Income			(43,992,933)
36	Oregon Apportionment Rate			23.7483%
37	State Tax Net Income			(10,447,574)
38	Show Computation of Tax:			
39	State Tax Rate			7.6%
40				(794,016)
41	Adjustments to Estimated State Tax			
42	Difference between 12/31/18 accrual and tax return			(236,465)
43	Provision for Current Federal Income Tax			(1,030,481)
44				
45				
46	Allocated to:	409.1	409.2	Total
47		(941,388)	(89,093)	(1,030,481)
48				
49				
50				
51				
52				
53				
54				
55				

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, 2019**

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

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Electric			
2				
3	Other			
4	TOTAL ELECTRIC			
5	Gas	17,102,003	(12,657,011)	11,570,300
6				
7	Other	-		
8	TOTAL GAS	17,102,003	(12,657,011)	11,570,300
9	Other (Specify)	-		
10	TOTAL (Account 190)	17,102,003	(12,657,011)	11,570,300
11	Classification of Totals			
12	Federal Income Tax	15,725,604	(11,672,828)	10,669,511
13	State Income Tax	1,376,399	(984,183)	900,789
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	12,147,162	(8,333,419)	7,631,472
18	Federal Income Tax - Oregon	3,578,442	(3,339,409)	3,038,039
19	State Income Tax - Oregon	1,376,399	(984,183)	900,789
20				
21				
22				

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS COPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
(762,822)	59,042	Regulatory accounts related to FAS 158 and OR rate change adjustments	1,019,871	Regulatory accounts related to FAS 158 and OR rate change adjustments	(8,179,495)	8,151,888	5
							6
						-	7
(762,822)	59,042		1,019,871		(8,179,495)	8,151,888	8
						-	9
(762,822)	59,042		1,019,871		(8,179,495)	8,151,888	10
							11
(702,510)	55,372		1,007,569		(7,586,907)	7,495,811	12
(60,312)	3,670		12,302		(592,588)	656,077	13
-	-		-		-	-	14
							15
							16
(528,077)	41,623		892,051		(5,807,667)	6,043,145	17
(174,433)	13,749		115,518		(1,779,240)	1,452,666	18
(60,312)	3,670		12,302		(592,588)	656,077	19
							20
							21
							22

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, 2019

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
							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) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2019**

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	(53,594,339)	(4,691,709)	2,939,172
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(53,594,339)	(4,691,709)	2,939,172
6	Other (Specify)			
7				
8				
9	Total (Account 282) Lines 5 thru 8	(53,594,339)	(4,691,709)	2,939,172
10	Classification of Totals			
11	Federal Income Tax	(49,763,427)	(4,173,671)	2,778,836
12	State Income Tax	(3,830,912)	(518,038)	160,336
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	(38,463,931)	(3,463,972)	2,131,944
	Federal Income Tax - Oregon	(11,299,496)	(709,699)	646,892
	State Income Tax - Oregon	(3,830,912)	(518,038)	160,336

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, 2019**

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS		CREDITS			
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	182.3 & 254	102,647,993	182.3 & 254	(105,168,567)	(57,867,450)	3
						-	4
-	-		102,647,993		(105,168,567)	(57,867,450)	5
						-	6
							7
							8
-	-		102,647,993		(105,168,567)	(57,867,450)	9
							10
-	-	254	102,570,773	254	(105,096,084)	(53,683,573)	11
-	-	182.3	77,220	182.3	(72,483)	(4,183,877)	12
-	-		-		-	-	13
-	-		79,481,537		(81,438,787)	(41,753,209)	
-	-		23,089,236		(23,657,297)	(11,930,364)	
-	-		77,220		(72,483)	(4,183,877)	

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(34,901,601)	(27,691,005)	19,054,142
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(34,901,601)	(27,691,005)	19,054,142
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(34,901,601)	(27,691,005)	19,054,142
10	Classification of Totals			
11	Federal Income Tax	(31,839,495)	(25,500,861)	17,658,724
12	State Income Tax	(3,062,106)	(2,190,144)	1,395,418
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	(26,957,638)	(20,430,423)	12,769,540
	Federal Income Tax - Oregon	(4,881,857)	(5,070,438)	4,889,184
	State Income Tax - Oregon	(3,062,106)	(2,190,144)	1,395,418

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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	Amounts Credited Account 411.2	DEBITS		CREDITS			
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	7,699,041	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	(1,630,337)	(37,469,760)	3
						-	4
-	-		7,699,041		(1,630,337)	(37,469,760)	5
						-	6
							7
							8
-	-		7,699,041		(1,630,337)	(37,469,760)	9
							10
-	-		7,080,815		(1,600,148)	(34,200,965)	11
-	-		618,226		(30,189)	(3,268,795)	12
-	-		-		-	-	13
-	-		5,274,665		(1,161,008)	(30,504,864)	
-	-		1,806,150		(439,140)	(3,696,101)	
-	-		618,226		(30,189)	(3,268,795)	

OREGON SUPPLEMENT

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

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

Line No.	Account Subdivision	Balance at Beginning of Year	Deferred For Year		Allocations to Current Year's Income		Adjustments	Balance at End of Year	Average period of Allocation to Income
			Account No	Amount	Account No	Amount			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(10,278)		ALLOCATED	23 Years
6	Total	0		0		(10,278)			
7	Other (list separately and show 3%, 4%, 7&, 10% and TOTAL)								
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
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25									

NOTES

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT		YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)		Dec. 31, 2019

STATE OF OREGON - SITUS UTILITY PLANT

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	233,716,290		233,716,290			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	11,359,613		11,359,613			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	245,075,903	-	245,075,903	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,697,915		1,697,915			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	246,773,818	-	246,773,818	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(102,609,519)		(102,609,519)			
15	Net Utility Plant (Line 13 less 14)	144,164,299	-	144,164,299	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(102,443,629)		(102,443,629)			
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	(165,890)		(165,890)			
22	Total In-Service (Total of lines 18 thru 21)	(102,609,519)	-	(102,609,519)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and depletion	-		-			
26	Total leased to others (Total of lines 24 and 25)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization	-		-			
30	Total Held for Future Use (Total of lines 28 & 29)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (lines 22,26, 30, 31 & 32)	(102,609,519)	-	(102,609,519)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant In Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction not Classified.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts on an estimated basis if necessary, and include entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year. **(Continue on page 25)**

LINE NO.	ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
1	1. Intangible Plant						
2	301 Organization						
3	302 Franchises and Consents	73,667					73,667
4	303 Miscellaneous Intangible Plant	2,947,821					2,947,821
5	TOTAL Intangible Plant	3,021,488	-	-	-	-	3,021,488
6	2. Production Plant						
7	Natural Gas Production & Gathering Plant						
8	325.1 Producing Lands	-					-
9	325.2 Producing leaseholds	-					-
10	325.3 Gas Rights	-					-
11	325.4 Rights-of-Way	-					-
12	325.5 Other Land and Land Rights	-					-
13	326 Gas Well Structures	-					-
14	327 Field Compressor Station Structures	-					-
15	328 Field Measuring and Regulating Station Structures	-					-
16	329 Other Structures	-					-
17	330 Producing Gas Wells- Well Construction	-					-
18	331 Producing Gas Wells- Well Equipment	-					-
19	332 Field Lines	-					-
20	333 Field Compressor Station Equipment	-					-
21	334 Field Measuring and Regulating Station Equipment	-					-
22	335 Drilling and Cleaning Equipment	-					-
23	336 Purification Equipment	-					-
24	337 Other Equipment	-					-
25	338 Unsuccessful Exploration & Development Costs	-					-
26	TOTAL Production & Gathering Plant	-	-	-	-	-	-
27	Products Extraction Plant						
28	340 Land and Land Rights	-					-
29	341 Structures and Improvements	-					-
30	342 Extraction and Refining Equipmnet	-					-
31	343 Pipe Lines	-					-
32	344 Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initally recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing sub-account classification of such plant conforming to the requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2019

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

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		TOTAL Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	13,131					13,131
80	365.2	Rights of Way	7,693					7,693
81	366	Structures and Improvements	-					-
82	367	Mains	5,818,920					5,818,920
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	36,162					36,162
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
86.a	372	ARO - Transmission	24,893		(304)			24,589
87		TOTAL Transmission Plant	5,900,799	-	(304)	-	-	5,900,495
88		5. Distribution Plant						
89	374	Land and Land Rights	377,949	(1,069)				376,880
90	375	Structures and Improvements	363,785					363,785
91	376	Mains	101,680,212	10,421,394	(93,476)			112,008,130
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	10,605,834	592,381	(74,427)			11,123,788
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	56,284,950	4,540,371	(53,263)			60,772,058
96	381	Meters	16,586,725	1,896,955	(1,901,719)	123,539		16,705,500
97	382	Meter Installations	9,659,588	77,983	(4,991)	(15,118)		9,717,462
98	383	House Regulators	2,847,027	192,129	(99,781)	21,205		2,960,580
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	2,199,898	263,850	(36,922)	15,118		2,441,944
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,827,543	880,729	(8,478)			5,699,794
103		TOTAL Distribution Plant	205,433,511	18,864,723	(2,273,057)	144,744	-	222,169,921

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, 2019**

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	4,516,175	604				4,516,779
107	391	Office Furniture and Equipment	178,477					178,477
108	392	Transportation Equipment	3,752,149	632,826	(66,417)			4,318,558
109	393	Stores Equipment	-					-
110	394	Tools, Shop and Garage Equipment	1,518,442	58,574	(21,087)			1,555,929
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	1,224,525	857,085	(773,605)	1		1,308,006
113	397	Communication Equipment	1,605,741	(1)				1,605,740
114	398	Miscellaneous Equipment	7,209					7,209
115		SUBTOTAL	13,296,019	1,549,088	(861,109)	1	-	13,983,999
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	13,296,019	1,549,088	(861,109)	1	-	13,983,999
118		TOTAL (Accounts 101 and 106)	227,651,817	20,413,811	(3,134,470)	144,745	-	245,075,903
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	227,651,817	20,413,811	(3,134,470)	144,745	-	245,075,903

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Acct. (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
2				
3				
4				
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52	TOTALS -	0	0	0

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, 2019**

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	Replace 12" HP main in Bend, OR (Phase 2)	726,190	
2	Install main to Pacific Cascade Heights in Bend, OR	631,656	
3			
4			
5			
6	Minor installation of mains, service lines, measuring and regulating stations,	340,069	
7	meter sets and telemetering, and etc.		
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43	T O T A L -	1,697,915	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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	(98,236,122)	(98,236,122)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(6,682,883)	(6,682,883)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(287,417)	(287,417)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(68,411)	(68,411)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(7,038,711)	(7,038,711)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	3,134,466	3,134,466		
12	Cost of Removal	392,971	392,971		
13	Salvage (credits)	(732,098)	(732,098)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	2,795,339	2,795,339		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	60,927	60,927		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(25,062)	(25,062)		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(102,443,629)	(102,443,629)		
	Section B. Balances at End of Year According to Functional Classifications				
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	(3,742,151)	(3,742,151)		
25	Distribution	(94,984,595)	(94,984,595)		
26	General	(4,169,602)	(4,169,602)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	526,386	526,386		
27	TOTAL (*Enter Total of Lines 18 thru 26*)	(102,443,629)	(102,443,629)		

NOTE:

Row 15.02 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

OREGON SUPPLEMENT

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT		YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)		Dec. 31, 2019

STATE OF OREGON - ALLOCATED

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	15,528,343		15,528,343			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	(331,367)		(331,367)			
7	Experimental Plant Unclassified	-					
8	TOTAL (*Enter Total of lines 3 thru 7*)	15,196,976	-	15,196,976	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	387,387		387,387			
12	Acquisition Adjustments	-					
13	Total Utility Plant (*Lines 8 thru 12*)	15,584,363	-	15,584,363	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(7,806,822)		(7,806,822)			
15	Net Utility Plant (Line 13 less 14)	7,777,541	-	7,777,541	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(2,777,228)		(2,777,228)			
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	(5,029,594)		(5,029,594)			
22	Total In-Service (*Lines 18 thru 21*)	(7,806,822)	-	(7,806,822)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and Depletion	-		-			
26	Total Leased to Others (*Lines 24 and 25*)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization and Depletion	-		-			
30	Total Leased to Others (*Lines 28 and 29*)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (*lines 22, 26, 30, 31, & 32*)	(7,806,822)	-	(7,806,822)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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	38,245			(487)		37,758
3	302	Franchises and Consents	-					-
4	303	Miscellaneous Intangible Plant	9,457,804	475,519	(27,952)	(120,338)		9,785,033
5		TOTAL Intangible Plant	9,496,049	475,519	(27,952)	(120,825)	-	9,822,791
6		2. Production Plant						
7		Natural Gas Production & Gathering Plant						
8	325.1	Producing Lands	-					-
9	325.2	Producing Leaseholds	-					-
10	325.3	Gas Rights	-					-
11	325.4	Rights-of-Way	-					-
12	325.5	Other lLand and Land Rights	-					-
13	326	Gas Well Structures	-					-
14	327	Field Compressor Station Structures	-					-
15	328	Field Measuring and Regulating Station Structures	-					-
16	329	Other Structures	-					-
17	330	Producing Gas Wells- Well Construction	-					-
18	331	Producing Gas Wells- Well Equipment	-					-
19	332	Field Lines	-					-
20	333	Field Compressor Station Equipment	-					-
21	334	Field Eeasuring and Regulating Station Equipment	-					-
22	335	Drilling and Cleaning Equipment	-					-
23	336	Purification Equipment	-					-
24	337	Other Equipment	-					-
25	338	Unsuccessful Exploration & Development Costs	-					-
26		TOTAL Production & Gathering Plant	-	-	-	-	-	-
27		Products Extraction Plant						
28	340	Land and Land Rights	-					-
29	341	Structures and Improvements	-					-
30	342	Extraction and Refining Equipmnet	-					-
31	343	Pipe Lines	-					-
32	344	Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		Total Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	-					-
80	365.2	Rights-of-Way	-					-
81	366	Structures and Improvements	-					-
82	367	Mains	-					-
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	-					-
85	370	Communication Equipment	-					-
86	371	Other Equipment	-					-
87		TOTAL Transmission Plant	-	-	-	-	-	-
88		5. Distribution Plant						
89	374	Land and Land Rights	23,867			(303)		23,564
90	375	Structures and Improvements	100,396	6,635	(1,062)	(1,277)		104,692
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	124,263	6,635	(1,062)	(1,580)	-	128,256

OREGON SUPPLEMENT

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
104		6. General Plant						
105	389	Land and Land Rights	240,110			(3,055)		237,055
106	390	Structures and Improvements	1,495,118	8,067		(19,023)		1,484,162
107	391	Office Furniture and Equipment	1,901,040	92,255		(24,188)		1,969,107
108	392	Transportation Equipment	513,992	87,478	(82,289)	(6,544)	19,970	532,607
109	393	Stores Equipment	10,837	2,303		(138)		13,002
110	394	Tools, Shop, and Garage Equipment	614,041	63,995	(859)	(7,813)		669,364
111	395	Laboratory Equipment	22,794		(1,529)	(291)		20,974
112	396	Power Operated Equipment	(24,319)	502		309		(23,508)
113	397	Communication Equipment	229,037	102,272		(2,913)		328,396
114	398	Miscellaneous Equipment	14,960			(190)		14,770
115		SUBTOTAL	5,017,610	356,872	(84,677)	(63,846)	19,970	5,245,929
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	5,017,610	356,872	(84,677)	(63,846)	19,970	5,245,929
118		TOTAL (Accounts 101 and 106)	14,637,922	839,026	(113,691)	(186,251)	19,970	15,196,976
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	14,637,922	839,026	(113,691)	(186,251)	19,970	15,196,976

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - ALLOCATED GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
2				
3				
4				
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46	T O T A L S -	0	0	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	387,387	
4			
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48	T O T A L -	387,387	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	(3,158,996)	(3,158,996)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(198,710)	(198,710)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(28,263)	(28,263)		
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*)	(226,973)	(226,973)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	85,744	85,744		
12	Cost of Removal	59	59		
13	Salvage (credits)	(22,871)	(22,871)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	62,932	62,932		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	510,424	510,424		
15.02	Adjustment Due to Change in Allocation Rate	35,385	35,385		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(2,777,228)	(2,777,228)		

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

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	-	-		
25	Distribution	(103,784)	(103,784)		
26	General	(3,186,385)	(3,186,385)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	512,941	512,941		
27	TOTAL (*Total of Lines 18 thru 26*)	(2,777,228)	(2,777,228)		

NOTE:

Row 15 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

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

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

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

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

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

Line No.	Description	NonCurrent (Acct 117) (a)	Current (Acct 164.1) (b)	LNG (Acct 164.2) (c)	LNG (Acct 164.3) (d)	Total (e)
1	Balance, beginning of year	Not allocated		Not allocated		Not allocated
2	Gas delivered to storage					
3	(contract account)					
4	Gas withdrawn from storage					
5	(contra account)			$ 242,806		$ 242,806
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					63,301
31	Amount per Mcf					3.84
32	Cost basis of withdrawals:					
33	Specify: average cost, lifo, fifo, (Explain any change in					F i f o
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						

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

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

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

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

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

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

5. Column instructions are as follows:

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

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

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

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

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

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

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

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

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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**		
9			
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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

7 Code (d)	State Code (e)	County Code (f)	Rate Schedule No. (g)	Rate Schedule Suffix (h)	Date of Contract (I)	Approx. BTU Per Cu Ft (j)	Gas Purchased - Mcf (14.73 psia 60 °F) (k)	Cost of Gas (l)	Cost Per Mcf (cents) (m)	LINE NO.
										1
						10.79	8,072,321	$ 20,875,351	259	2
										3
								$ 578,100	n/a	4
										5
								$ 9,168,467	n/a	6
										7
							8,072,321	**$ 30,621,918**	n/a	8
										9
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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

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.

			Natural Gas			Manufactured Gas	
LINE NO.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	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	812	7,559	$ 15,089	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	**TOTAL**		7,559	$ 15,089			

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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		8,072,321
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		8,072,321
14	Gas of others received for transportation		25,313,504
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		260,457
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		33,646,282

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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		710,666
39	(ii) Other distribution system sales		7,823,803
40	TOTAL DISTRIBUTION SYSTEM SALES		8,534,469
41	d. Interdepartmental sales		
42	TOTAL SALES		8,534,469
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		25,313,504
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		25,313,504
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		7,559
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		33,855,532
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		(209,250)
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		(209,250)
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		33,646,282

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - Miscellaneous General Expeness (Account 930.2)

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

LINE NO.	ITEMS (a)	TOTAL (b)	AMOUNT APPLICABLE TO STATE OF OREGON (c)	AMOUNT APPLICABLE TO OTHER STATES (d)
1	Industry association dues.	284,608	76,398	208,210
2	Experimental and general research expenses.			
	a. Gas Research Institute (GRI)			
	b. Other			
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing oustanding securities of the respondent			
4				
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex and MDU for CNGC's share of corporate banking fees)			
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	451,891	112,205	339,686
7	Miscellaneous under $250,000			
8	2,725 items	296,140	62,148	233,992
9				
10				
	TOTAL	**1,032,639**	**250,751**	**781,888**

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, 2019

STATE OF OREGON - POLITICAL ADVERTISING

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

LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	NONE		
	TOTAL		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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	Association of WA Business-Natural Gas Coalition Funds to be used to defeat Proposed Rule by City of Bellingham to ban the use of Natural Gas.	426.4	43,453
	TOTAL		**43,453.00**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	MDU/MDUR Allocated - approved in Order 07-418	107	2,130,631	529,036
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	211,302	52,466
3	MDU/MDUR Allocated - approved in Order 07-418	426.2	(569,914)	(141,510)
4	MDU/MDUR Allocated - approved in Order 07-418	426.4	306,254	76,043
5	MDU/MDUR Allocated - approved in Order 07-418	426.5	1,556	-
6	MDU/MDUR Allocated - approved in Order 07-418	813	172,370	42,800
7	MDU/MDUR Allocated - approved in Order 07-418	870	1,236,084	306,929
8	MDU/MDUR Allocated - approved in Order 07-418	874	465,129	226,068
9	MDU/MDUR Allocated - approved in Order 07-418	875	115,170	28,597
10	MDU/MDUR Allocated - approved in Order 07-418	878	-	-
11	MDU/MDUR Allocated - approved in Order 07-418	880	1,235,529	306,745
12	MDU/MDUR Allocated - approved in Order 07-418	881	69,876	8,606
13	MDU/MDUR Allocated - approved in Order 07-418	885	80,218	19,925
14	MDU/MDUR Allocated - approved in Order 07-418	887	619,344	18,563
15	MDU/MDUR Allocated - approved in Order 07-418	887.1	7,141	1,773
16	MDU/MDUR Allocated - approved in Order 07-418	892	200	50
17	MDU/MDUR Allocated - approved in Order 07-418	894	48,297	11,821
18	MDU/MDUR Allocated - approved in Order 07-418	901	44,898	11,148
19	MDU/MDUR Allocated - approved in Order 07-418	902	211,446	52,502
20	MDU/MDUR Allocated - approved in Order 07-418	903	5,336,032	1,324,937
21	MDU/MDUR Allocated - approved in Order 07-418	904	1,209,258	215,041
22	MDU/MDUR Allocated - approved in Order 07-418	908	279,237	62,967
23	MDU/MDUR Allocated - approved in Order 07-418	909	166,830	51,574
24	MDU/MDUR Allocated - approved in Order 07-418	920	7,255,805	1,801,616
25	MDU/MDUR Allocated - approved in Order 07-418	921	3,391,431	842,020
26	MDU/MDUR Allocated - approved in Order 07-418	922	(245,018)	(60,728)
27	MDU/MDUR Allocated - approved in Order 07-418	923	267,373	67,930
28	MDU/MDUR Allocated - approved in Order 07-418	925	9,351	2,322
29	MDU/MDUR Allocated - approved in Order 07-418	926	28,351	7,040
30	MDU/MDUR Allocated - approved in Order 07-418	930.1	30,962	7,688
31	MDU/MDUR Allocated - approved in Order 07-418	930.2	753,502	187,093
32	MDU/MDUR Allocated - approved in Order 07-418	931	1,384,279	343,716
33	MDU/MDUR Allocated - approved in Order 07-418	932	2,101	522
34	Other Services	VAR	-	-
	TOTALS		26,255,025	6,405,300

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

STATE OF OREGON - Donations and Memberships

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

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	*(a) Contributions to and memberships in charitable organizations:*			
2	*MDU Resources Foundation (Bismarck, ND)*	426.1	113,246	28,119
3	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,415
4	United Way (WA and OR)	426.1	1,945	859
5	Other Organizations (41 organizations)	908.0/930.2/921.0	19,375	12,875
6	Total contributions to and memberships in charitable organizations		184,566	54,268
7	*(b) Organizations of the Utility Industry:*			
8	American Gas Association (Washington D.C.)	426.4/930.2	117,855	29,263
9	Northwest Gas Association (West Linn, OR)	930.2	55,218	13,711
10	Western Energy Institute (Portland, OR)	921.0/930.2	10,120	2,513
11	North American Energy Standards Board (Houston, TX)	921.0	7,500	1,862
12	Other Organizations (6 organizations)	908.0/930.2/921.0	3,806	1,535
13	Total contributions to Organizations of the Utility Industry		194,499	48,884
14	*(c) Technical and Professional Organizations*			
15	National Association of Corrosion Engineers (Houston, TX)	921.0	2,000	497
16	CPA State Boards and Societies	921.0	1,351	335
17	PE State Boards and Societies	921.0/870.0	613	152
18	Other Organizations (20 organizations)	921.0/930.2	5,212	1,294
19	Total contributions to Professional Organizations		9,176	2,278
20	*(d) Commercial and Trade Organizations*			
21	Association of Washington Business (Olympia, WA)	930.2/921.0	47,475	11,788
22	Chamber of Commerce-13 (OR)	880.0/930.2	26,981	14,916
23	Economic Development Councils-5 (OR)	426.1/930.2	20,681	13,165
24	Other Organizations (3 organizations)	426.1/908.0/930.2	4,927	1,356
25	Total contributions to Commercial and Trade Organizations		100,064	41,225
26	*(e) Other Organizations & Donations*			
27	MDU Resources expenses (Bismarck, ND)	426.1/426.4/921.0	34,116	8,471
28	Grandridge Business Park (Kennewick WA)	921.0	10,181	2,528
29	Other Organizations	930.2	50	50
30	Total Other Organizations		44,347	11,049
31				
32				
33				
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	TOTAL		**532,652**	**157,704**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2019

STATE OF OREGON - OFFICERS' SALARIES

1. Report below the name, title and salary for the year for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principle business unit, division or function (such as sales, administration or finance) and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and date the change in incumbency was made.
3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

LINE NO.	TITLE (a)	NAME OF OFFICER (b)	SALARY FOR YEAR TOTAL (a)	SALARY FOR YEAR OREGON (a)
1	Assistant Secretary 2/	Julie A. Krenz	4/	
2	Assistant Secretary 2/	Karl A. Liepitz	4/	
3	Chairman of the Board 2/	David L. Goodin	4/	
4	Chief Information Officer 2/	Margaret (Peggy) A. Link	4/	
5	Controller 1/	Tammy J. Nygard	4/	
6	Executive VP -Reg Affairs, Cust Service & Administration/1	Garret Senger	4/	
7	Executive VP-Bus Development & Gas Supply 1/	Scott W. Madison	4/	
8	General Counsel and Secretary 2/	Daniel S. Kuntz	4/	
9	President and CEO of MDU Utilities Group 1/	Nicole A. Kivisto	4/	
10	Treasurer 2/	Jason L. Vollmer	4/	
11	VP Field Operations 1/	Eric P. Martuscelli	4/	
12	VP-Engineering & Operations Services 1/	Patrick C. Darras	4/	
13	VP-Human Resources 2/	Anne M. Jones	4/	
14	VP-Regulatory Affairs & Cust Service 1/	Mark A. Chiles	4/	
15	VP-Safety, Process Improvement & Operating Systems 1/	Hart Gilchrist	4/	
16				
17				
18	1/ Salary includes amount allocated to CNGC from MDU			
19	2/ Salary includes amount allocated to CNGC from MDUR			
20	4/ Confidential salary data included on filed reports with OPUC.			
21				
22				
23				
24				
25				

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

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

LINE NO.	NAME OF RECIPIENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Eugene Water & Electric Board	Construction	743,205
2	Heath consultants, Inc.	Construction	189,789
3	McDowell Rackner & Gibson	Consulting	93,477
4	Brothers Pipeline Corp.	Construction	74,418
5	Deloite & Touche	Audit	68,562
6	Das-CO of Idaho	Construction	55,980
7	One Call Concepts, Inc.	Construction	27,895
8	Knife River-Western OR	Construction	25,818
9	Other		6,390
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14			
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23			
24			
25			
	TOTAL		**1,285,534**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2019**

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

Oregon Production Statistics (therms)	
Gas Produced	
Gas Purchased	362,992,918
Total Receipts	362,992,918

Gas Sales	365,168,867
Gas used by Company	81,548
Gas Delivered to LNG Storage - Net	
Losses & Billing Delay	(2,257,497)
Total Disbursements	362,992,918

Oregon Revenue by Service Class	
Residential	$ 37,648,100
Commercial & Industrial	$ 25,020,626
Firm	
Interruptible	
Transportation	$ 4,432,276
Total	$ 67,101,002

Gas Sold in Therms (Oregon)	
Residential	49,965,826
Commercial & Industrial	42,108,299
Firm	
Interruptible	
Transportation	273,094,742
Total	365,168,867

Average Number of Customers	
Residential	65,860
Commercial & Industrial	10,305
Firm	
Interruptible	
Transportation	37
Total	76,202

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, 2019

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 Terminaling and Processing				
32	Transmission				
33	Distribution	3,338,854			**3,338,854**
34	Customer Accounts	1,049,373			**1,049,373**
35	Customer Service and Informational	159,236			**159,236**
36	Sales	940			**940**
37	Administrative and General	1,496,715			**1,496,715**
38	TOTAL Operation (Total of lines 28 thru 37)	**6,045,118**	**-**	**-**	**6,045,118**
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	1,000,880			**1,000,880**
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	**1,000,880**	**-**	**-**	**1,000,880**
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)				
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	4,339,734			**4,339,734**
56	Customer Accounts (Total of line 34)	1,049,373			**1,049,373**
57	Customer Service and Informational (Total of line 35)	159,236			**159,236**
58	Sales (Total of line 36)	940			**940**
59	Administrative and General (Total of lines 37 and 46)	1,496,715			**1,496,715**
60	Total Operation and Maintenance (Total of lines 50 thru 59)	**7,045,998**	**-**	**-**	**7,045,998**
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	**7,045,998**	**-**	**-**	**7,045,998**
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	1,943,262			**1,943,262**
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	**1,943,262**	**-**	**-**	**1,943,262**
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	163,414			**163,414**
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	**163,414**	**-**	**-**	**163,414**
75	PTO/Incentive/Severance Pay Liabilities	421,399			**421,399**
76	TOTAL Other Accounts	**421,399**	**-**	**-**	**421,399**
77	TOTAL SALARIES AND WAGES	**9,574,073**	**-**	**-**	**9,574,073**

	Year 2016 Debit (Credit)	Year 2017 Debit (Credit)	Year 2018 Debit (Credit)	Year 2019 Debit (Credit)
	-	-	0	-
100-199 Assets and Other Debits.				
1. Utility Plant				
101 Gas plant in service.	-	-	(0)	-
101.1 Property under capital leases.				
102 Gas plant purchased or sold.				
103 Experimental gas plant unclassified.				
104 Gas plant leased to others.				
105 Gas plant held for future use.				
105.1 Production properties held for future use.				
106 Completed construction not classified - Gas.				
107 Construction work in progress - Gas.	12,898,870	8,458,804	12,854,207	31,106,072
108 Accumulated provision for depreciation of gas utility plant.	(442,537,270)	(463,301,411)	(473,404,421)	(487,657,727)
109 [Reserved]			-	-
111 Accumulated provision for amortization and depletion of gas utility plant.	(10,807,312)	(13,839,975)	(17,326,335)	(20,671,419)
111.1-111.2 [Reserved]			-	-
112 [Reserved]			-	-
113.1-113.2 [Reserved]			-	-
114 Gas plant acquisition adjustments.			-	-
115 Accumulated provision for amortization of gas plant acquisition adjustments.			-	-
116 Other gas plant adjustments.			-	-
117.1 Gas stored-Base gas.			-	-
117.2 System balancing gas.			-	-
117.3 Gas stored in reservoirs and pipelines-noncurrent.			-	-
117.4 Gas owed to system gas.			-	-
118 Other utility plant.			-	-
119 Accumulated provision for depreciation and amortization of other utility plant.			-	-
2. Other Property and Investments				-
121 Nonutility property.	202,030	202,030	202,030	197,964
122 Accumulated provision for depreciation and amortization of nonutility property.			-	-
123 Investment in associated companies.			-	-
123.1 Investment in subsidiary companies.			-	-
124 Other investments.	10,932,832	11,692,638	12,371,315	11,991,542
125 Sinking funds.			-	-
126 Depreciation fund.			-	-
128 Other special funds.			-	-
3. Current and Accrued Assets				
131 Cash.	3,539,113	2,727,130	3,203,159	6,896,977
132 Interest special deposits.			-	-
133 Dividend special deposits.			-	-
134 Other special deposits.			-	-
135 Working funds.	2,750	1,550	1,150	-
136 Temporary cash investments.			-	-
141 Notes receivable.			-	-
142 Customer accounts receivable.	10,813,648	12,549,415	10,776,951	15,555,347
143 Other accounts receivable.	1,813,282	2,255,787	13,165,937	5,086,879
144 Accumulated provision for uncollectible accounts - Cr.	(471,151)	(471,321)	(460,922)	(513,355)
145 Notes receivable from associated companies.			-	-
146 Accounts receivable from associated companies.	60,060	-	129,531	140,108
151 Fuel stock.			-	-
152 Fuel stock expenses undistributed.			-	-
153 Residuals and extracted products.			-	-
154 Plant materials and operating supplies (Major only).	7,223,893	8,026,535	5,694,283	6,476,402
155 Merchandise.			-	-
156 Other materials and supplies.			-	-
163 Stores expense undistributed.			-	-
164.1 Gas stored - current.	126,656	587,529	396,659	893,659
164.2 Liquefied natural gas stored.	1,705,164	2,230,775	1,940,549	1,844,137
164.3 Liquefied natural gas held for processing.			-	-
165 Prepayments.	2,456,770	3,305,688	4,497,288	5,502,645
166 Advances for gas exploration, development, and production.			-	-
167 Other advances for gas.			-	-
171 Interest and dividends receivable.			-	-
172 Rents receivable.			-	-
173 Accrued utility revenues.	34,522,282	32,360,206	25,164,950	32,004,471
174 Miscellaneous current and accrued assets.			-	-
175 Derivative Instrument Assets.			-	138,098
4. Deferred Debits				
181 Unamortized debt expense.	2,042,178	1,646,972	1,624,524	2,122,842
182.1 Extraordinary property losses.			-	-
182.2 Unrecovered plant and regulatory study costs.			-	-
182.3 Other regulatory assets.	49,627,341	47,795,198	56,168,845	48,264,135
183.1 Preliminary natural gas survey and investigation charges.			-	108,101
183.2 Other preliminary survey and investigation charges.	-	367	-	-
184 Clearing accounts.	104,615	39,416	59,785	45,130
185 Temporary facilities.			-	-
186 Miscellaneous deferred debits.	70,888,337	70,740,286	79,056,464	85,211,361
187 Deferred losses from disposition of utility plant.			-	-
188 Research, development, and demonstration expenditures.			-	-
189 Unamortized loss on reacquired debt.	826,242	785,271	744,300	703,330
190 Accumulated deferred income taxes.	26,488,327	16,343,135	17,102,003	8,151,888
191 Unrecovered purchased gas costs.			-	-
200-299 Liabilities and Other Credits.				
5. Proprietary Capital				
201 Common stock issued.	(1,000)	(1,000)	(1,000)	(1,000)
202 Common stock subscribed.			-	-
203 Common stock liability for conversion.			-	-
204 Preferred stock issued.			-	-
205 Preferred stock subscribed.			-	-
206 Preferred stock liability for conversion.			-	-
207 Premium on capital stock.	(160,698,668)	(192,553,017)	(222,117,553)	(266,117,553)
208 Donations received from stockholders.			-	-
209 Reduction in par or stated value of capital stock.			-	-
210 Gain on resale or cancellation of reacquired capital stock.			-	-
211 Miscellaneous paid-in capital.			-	-
212 Installments received on capital stock.			-	-
213 Discount on capital stock.			-	-
214 Capital stock expense.			-	-
215 Appropriated retained earnings.			-	-
216 Unappropriated retained earnings.	(38,204,913)	(31,852,511)	(30,688,673)	(34,416,894)
216.1 Unappropriated undistributed subsidiary earnings.			-	-
217 Reacquired capital stock.			-	-
219 Other Comprehensive Income	-	(1,270,661)	(2,318,457)	(2,075,442)
6. Long-Term Debt				
221 Bonds.			-	-
222 Reacquired bonds.			-	-
223 Advances from associated companies.			-	-
224 Other long-term debt.	(214,471,000)	(214,431,000)	(268,211,000)	(353,814,000)
225 Unamortized premium on long-term debt.			-	-
226 Unamortized discount on long-term debt - Debit.			-	-
7. Other Noncurrent Liabilities.				
227 Obligations under capital leases - noncurrent.			-	-
228.1 Accumulated provision for property insurance.			-	
228.2 Accumulated provision for injuries and damages.	(15,498,768)	(14,261,343)	(13,232,381)	(10,454,118)
228.3 Accumulated provision for pensions and benefits.	(7,687,634)	(8,407,713)	(5,811,780)	(6,107,472)
228.4 Accumulated miscellaneous operating provisions.	(24,135)	(48,270)	(24,135)	(24,135)
229 Accumulated provision for rate refunds.		-	(1,558,020)	-
230 Asset Retirement Obligations.	(54,807,880)	(61,208,026)	(66,788,046)	(74,293,817)
8. Current and Accrued Liabilities				
231 Notes payable.	-	(17,300,000)	-	-
232 Accounts payable.	(28,763,011)	(29,768,720)	(66,439,118)	(44,250,029)
233 Notes payable to associated companies.			-	-
234 Accounts payable to associated companies.	(1,606,767)	(1,690,801)	(2,007,577)	(2,644,766)
235 Customer deposits.	(874,939)	(904,903)	(893,105)	(783,319)
236 Taxes accrued.	(8,418,892)	(8,002,294)	(7,285,166)	(8,825,425)
237 Interest accrued.	(3,113,255)	(3,121,957)	(3,155,341)	(3,373,380)
238 Dividends declared.	(4,160,000)	(3,300,000)	(2,960,000)	(2,480,000)
239 Matured long-term debt.			-	-
240 Matured interest.			-	-
241 Tax collections payable.	(3,542)	-	(1,309)	(314)
242 Miscellaneous current and accrued liabilities.	(9,694,740)	(8,843,156)	(8,958,797)	(9,592,836)
243 Obligations under capital leases - current.			-	-
9. Deferred Credits				
252 Customer advances for construction.	(4,482,130)	(4,487,518)	(4,315,901)	(4,195,587)
253 Other deferred credits.	(18,664,938)	980,392	31,014,246	81,595,224
254 Other regulatory liabilities.	(3,780,681)	(64,721,420)	(62,967,793)	(58,505,890)
255 Accumulated deferred investment tax credits.	(324,288)	(286,113)	(243,929)	(201,910)
256 Deferred gains from disposition of utility plant.			-	-
257 Unamortized gain on reacquired debt.			-	-
281 Accumulated deferred income taxes - Accelerated amortization property.			-	-
282 Accumulated deferred income taxes - Other property.	(100,067,346)	(52,078,937)	(53,594,339)	(57,867,450)
283 Accumulated deferred income taxes - Other.	(36,157,096)	(25,378,377)	(34,901,601)	(37,469,760)
300-399 Plant Accounts.				
1. Intangible Plant				
301 Organization.	152,066	152,066	152,066	152,066
302 Franchises and consents.	211,825	211,825	211,825	211,825
303 Miscellaneous intangible plant.	33,571,462	43,233,241	44,171,295	45,973,820
2. Production Plant				
a. manufactured gas production plant				
304 Land and land rights.			-	
305 Structures and improvements.			-	
306 Boiler plant equipment.			-	
307 Other power equipment.			-	
308 Coke ovens.			-	
309 Producer gas equipment.			-	
310 Water gas generating equipment.			-	
311 Liquefied petroleum gas equipment.			-	
312 Oil gas generating equipment.			-	
313 Generating equipment - Other processes.			-	
314 Coal, coke, and ash handling equipment.			-	
315 Catalytic cracking equipment.			-	
316 Other reforming equipment.			-	
317 Purification equipment.			-	
318 Residual refining equipment.			-	
319 Gas mixing equipment.			-	
320 Other equipment.			-	
b. natural gas production plant				
B.1. Natural Gas Production and Gathering Plant				
325.1 Producing lands.			-	
325.2 Producing leaseholds.			-	
325.3 Gas rights.			-	
325.4 Rights-of-way.			-	
325.5 Other land and land rights.			-	
326 Gas well structures.			-	
327 Field compressor station structures.			-	
328 Field measuring and regulating station structures.			-	
329 Other structures.			-	
330 Producing gas wells - Well construction.			-	
331 Producing gas wells - Well equipment.			-	
332 Field lines.			-	
333 Field compressor station equipment.			-	
334 Field measuring and regulating station equipment.			-	
335 Drilling and cleaning equipment.			-	
336 Purification equipment.			-	
337 Other equipment.			-	
338 Unsuccessful exploration and development costs.			-	
B.2. Products Extraction Plant				
340 Land and land rights.			-	
341 Structures and improvements.			-	
342 Extraction and refining equipment.			-	
343 Pipe lines.			-	
344 Extracted product storage equipment.			-	
345 Compressor equipment.			-	
346 Gas measuring and regulating equipment.			-	
347 Other equipment.			-	
3. Natural Gas Storage and Processing Plant				
a. underground storage plant				
350.1 Land.			-	
350.2 Rights-of-way.			-	
351 Structures and improvements.			-	
352 Wells.			-	
352.1 Storage leaseholds and rights.			-	
352.2 Reservoirs.			-	
352.3 Nonrecoverable natural gas.			-	
353 Lines.			-	
354 Compressor station equipment.			-	
355 Measuring and regulating equipment.			-	
356 Purification equipment.			-	
357 Other equipment.			-	
b. other storage plant				
360 Land and land rights.			-	
361 Structures and improvements.			-	
362 Gas holders.			-	
363 Purification equipment.			-	
363.1 Liquefaction equipment.			-	
363.2 Vaporizing equipment.			-	
363.3 Compressor equipment.			-	
363.4 Measuring and regulating equipment.			-	
363.5 Other equipment.			-	
c. base load liquefied natural gas terminaling and processing plant				
364.1 Land and land rights .			-	
364.2 Structures and improvements.			-	
364.3 LNG processing terminal equipment.			-	
364.4 LNG transportation equipment.			-	
364.5 Measuring and regulating equipment.			-	
364.6 Compressor station equipment.			-	
364.7 Communication equipment.			-	
364.8 Other equipment.			-	
4. Transmission Plant				
365.1 Land and land rights.	224,536	224,536	224,536	224,536
365.2 Rights-of-way.	1,026,089	1,026,089	1,026,089	1,026,089
366 Structures and improvements.			-	-
367 Mains.	21,858,600	22,244,572	22,171,656	22,103,530
368 Compressor station equipment.			-	-
369 Measuring and regulating station equipment.	192,301	192,301	180,823	180,823
370 Communication equipment.			-	-
371 Other equipment.			-	-
372 Asset Retirement Costs for Transmission Plant	87,147	88,011	87,720	86,637
5. Distribution Plant				
374 Land and land rights.	2,486,528	2,662,738	2,663,807	2,711,069
375 Structures and improvements.	1,459,328	1,460,862	1,465,897	1,488,340
376 Mains.	428,486,175	465,650,883	506,416,844	541,901,418
377 Compressor station equipment.	2,097,767	2,097,767	2,097,767	2,097,767
378 Measuring and regulating station equipment - General.	28,118,944	31,749,130	33,041,936	36,723,650
379 Measuring and regulating station equipment - City gate check stations.			-	-
380 Services.	214,076,819	228,416,660	249,437,259	269,515,163
381 Meters.	56,271,855	57,962,781	65,020,482	65,001,945
382 Meter installations.	31,328,381	32,866,611	33,655,296	33,847,282
383 House regulators.	10,387,457	10,687,871	11,160,435	11,519,765
384 House regulatory installations.			-	-
385 Industrial measuring and regulating station equipment.	10,034,002	10,530,822	11,641,827	12,160,232
386 Other property on customers' premises.			-	-
387 Other equipment.			-	-
388 Asset Retirement Costs for Distribution Plant	16,492,357	19,917,157	22,097,038	26,251,194
6. General Plant				
389 Land and land rights.	3,468,083	3,468,083	3,468,083	3,997,891
390 Structures and improvements.	19,527,428	19,677,023	20,024,461	22,969,230
391 Office furniture and equipment.	7,525,935	7,786,718	8,287,578	8,669,701
392 Transportation equipment.	15,441,850	16,598,163	17,137,416	18,293,048
393 Stores equipment.	66,925	66,925	66,925	76,202
394 Tools, shop and garage equipment.	7,346,276	7,453,063	8,967,475	9,390,985
395 Laboratory equipment.	126,158	126,158	119,908	89,722
396 Power operated equipment.	3,493,545	3,872,924	4,989,380	3,866,196
397 Communication equipment.	7,055,046	7,132,823	7,159,952	7,605,008
398 Miscellaneous equipment.	79,679	79,679	80,968	80,968
399 Other tangible property.			-	-
400-432, 434-435 Income Accounts.				
1. Utility Operating Income				
operating expenses				
400 Operating revenues.			-	-
401 Operation expense.			-	-
402 Maintenance expense.			-	-
403 Depreciation expense.	22,501,731	24,014,068	26,303,413	29,230,448
404.1 Amortization and depletion of producing natural gas land and land rights.			-	-
404.2 Amortization of underground storage land and land rights.	2,736,728	3,032,663	3,486,360	3,457,659
404.3 Amortization of other limited-term gas plant.			-	-
405 Amortization of other gas plant.			-	-
406 Amortization of gas plant acquisition adjustments.			-	-
407.1 Amortization of property losses, unrecovered plant and regulatory study costs.			-	-
407.2 Amortization of conversion expense.			-	-
407.3 Regulatory debits.			-	-
407.4 Regulatory credits.			-	-
408 [Reserved]			-	-
408.1 Taxes other than income taxes, utility operating income.	25,926,633	29,055,993	28,430,305	30,542,472
409 [Reserved]			-	-
409.1 Income taxes, utility operating income.	4,283,371	(2,363,280)	(5,881,800)	(12,466,886)
410 [Reserved]			-	-
410.1 Provision for deferred income taxes, utility operating income.	1,863,084	11,134,553	17,131,551	45,039,725
411 [Reserved]			-	-
411.1 Provision for deferred income taxes - Credit, utility operating income.		-	(10,752,441)	(33,563,613)
411.3 [Reserved]			-	-
411.4 Investment tax credit adjustments, utility operations.	(48,834)	(38,175)	(42,184)	(42,019)
411.6 Gains from disposition of utility plant.			-	-
411.7 Losses from disposition of utility plant. Total utility operating expenses.			-	-
other operating income				
412 Revenues from gas plant leased to others.			-	-
413 Expenses of gas plant leased to others.			-	-
414 Other utility operating income. Net utility operating income.			-	-
2. Other Income and Deductions				
a. other income				
415 Revenues from merchandising, jobbing and contract work.			-	-
416 Costs and expenses of merchandising, jobbing and contract work.			-	-
417 Revenues from nonutility operations.	(6,276)	(10,781)	(8,687)	(8,174)
417.1 Expenses of nonutility operations.			-	-
418 Nonoperating rental income.			-	-
418.1 Equity in earnings of subsidiary companies.			-	-
419 Interest and dividend income.			-	-
419.0 Interest and dividend income.	(610,340)	(568,811)	(513,668)	(5,013,882)
419.1 Allowance for other funds used during construction.	(361,162)	(177,923)	(47,519)	105
421 Miscellaneous nonoperating income.	(17,666)	(28,939)	(25,876)	(4,734)
421.1 Gain on disposition of property. Total other income.			-	(934)
b. other income deductions				
421.2 Loss on disposition of property.			-	-
425 Miscellaneous amortization.			-	-
426 [Reserved]			-	-
426.1 Donations.	232,468	299,157	147,336	251,619
426.2 Life insurance.	-	(291,752)	452,957	(783,273)
426.3 Penalties.	1,001,184	-	51	94
426.4 Expenditures for certain civic, political and related activities.	128,203	128,933	165,578	306,254
426.5 Other deductions. Total other income deductions. Total other income and ded	1,437	1,097	615,677	1,556
c. taxes applicable to other income and deductions				
408.2 Taxes other than income taxes, other income and deductions.	3,164	1,106	1,145	1,072
409.2 Income taxes, other income and deductions.	(202,120)	(286)	(271,794)	498,050
410.2 Provision for deferred income taxes, other income and deductions.		-	152,659	762,822
411.2 Provision for deferred income taxes - Credit, other income and deductions.		-	(114,241)	(59,042)
411.5 Investment tax credit adjustments, nonutility operations.			-	-
420 Investment tax credits. Total taxes on other income and deductions. Net other income and deductions.			-	-

3. Interest Charges				
427 Interest on long-term debt.	11,144,573	11,403,441	11,687,433	14,202,081
428 Amortization of debt discount and expense.	171,932	454,448	200,173	216,975
428.1 Amortization of loss on reacquired debt.	40,971	40,971	40,971	40,971
429 Amortization of premium on debt - Credit.			-	-
429.1 Amortization of gain on reacquired debt - Credit.			-	-
430 Interest on debt to associated companies.			-	-
431 Other interest expense.	653,866	505,177	359,840	1,362,795
432 Allowance for borrowed funds used during construction - Credit. Net interest charg	(284,975)	(253,406)	(291,153)	(649,294)
4. Extraordinary Items				
434 Extraordinary income.			-	-
435 Extraordinary deductions.			-	-
409.3 Income taxes, extraordinary items. Net income			-	-
433, 436-439 Retained Earnings Accounts.				
Retained Earnings Chart of Accounts				
433 Balance transferred from income.			-	-
436 Appropriations of retained earnings.			-	-
437 Dividends declared - preferred stock.			-	-
438 Dividends declared - common stock.	16,655,599	13,238,242	10,652,776	10,413,231
439 Adjustments to retained earnings.			273,681	-
480-499 Revenue Accounts.				
1. Sales of Gas				
480 Residential sales.	(148,255,469)	(160,886,676)	(161,603,290)	(172,399,518)
481 Commercial and industrial sales.	(94,221,079)	(100,868,460)	(100,897,968)	(111,750,808)
482 Other sales to public authorities.			-	-
483 Sales for resale.			-	-
484 Interdepartmental sales.			-	-
485 Intracompany transfers.			-	-
2. Other Operating Revenues				
487 Forfeited discounts.			-	-
488 Miscellaneous service revenues.	(988,098)	(999,833)	(925,187)	(697,653)
489.0 Revenues from transportation of gas of others through gathering facilities.			(27,295,347)	(28,256,098)
489.1 Revenues from transportation of gas of others through gathering facilities.			163,339	(270,806)
489.2 Revenues from transportation of gas of others through transmission facilities.			-	-
489.3 Revenues from transportation of gas of others through distribution facilities.	(25,261,174)	(27,389,122)	-	-
489.4 Revenues from storing gas of others.			-	-
490 Sales of products extracted from natural gas.			-	-
491 Revenues from natural gas processed by others.			-	-
492 Incidental gasoline and oil sales.			-	-
493 Rent from gas property.	(133,624)	(114,496)	(11,100)	(12,000)
494 Interdepartmental rents.			(114,312)	(170,208)
495 Other gas revenues.	(152,621)	(190,273)	(124,553)	(104,949)
496 Provision for rate refunds		-	3,982,745	(733,536)
700-899 Production, Transmission and Distribution Expenses.				
1. Production Expenses				
a. manufactured gas production				
A.1. Steam Production				
Operation				
700 Operation supervision and engineering.			-	
701 Operation labor.			-	
702 Boiler fuel.			-	
703 Miscellaneous steam expenses.			-	
704 Steam transferred - Credit.			-	
Maintenance				
705 Maintenance supervision and engineering.			-	
706 Maintenance of structures and improvements.			-	
707 Maintenance of boiler plant equipment.			-	
708 Maintenance of other steam production plant			-	
A.2. Manufactured Gas Production				
Operation				
710 Operation supervision and engineering			-	
Production Labor and Expenses				
711 Steam expenses.			-	
712 Other power expenses.			-	
713 Coke oven expenses.			-	
714 Producer gas expenses.			-	
715 Water gas generating expenses.			-	
716 Oil gas generating expenses.			-	
717 Liquefied petroleum gas expenses.			-	
718 Other process production expenses.			-	
gas fuels				
719 Fuel under coke ovens.			-	
720 Producer gas fuel.			-	
721 Water gas generator fuel.			-	
722 Fuel for oil gas.			-	
723 Fuel for liquefied petroleum gas process.			-	
724 Other gas fuels.			-	
gas raw materials				
725 Coal carbonized in coke ovens.			-	
726 Oil for water gas.			-	
727 Oil for oil gas.			-	
728 Liquefied petroleum gas.			-	
729 Raw materials for other gas processes.			-	
730 Residuals expenses.			-	
731 Residuals produced - Credit.			-	
732 Purification expenses.			-	
733 Gas mixing expenses.			-	
734 Duplicate charges - Credit.			-	
735 Miscellaneous production expenses.			-	
736 Rents.			-	
Maintenance				
740 Maintenance supervision and engineering.			-	
741 Maintenance of structures and improvements.			-	
742 Maintenance of production equipment.			-	
b. natural gas production expenses				
B.1. Natural Gas Production and Gathering				
Operation				
750 Operation supervision and engineering.			-	
751 Production maps and records.			-	
752 Gas wells expenses.			-	
753 Field lines expenses.			-	
754 Field compressor station expenses.			-	
755 Field compressor station fuel and power.			-	
756 Field measuring and regulating station expenses.			-	
757 Purification expenses.			-	
758 Gas well royalties.			-	
759 Other expenses.			-	
760 Rents.			-	
Maintenance				
761 Maintenance supervision and engineering.			-	
762 Maintenance of structures and improvements.			-	
763 Maintenance of producing gas wells.			-	
764 Maintenance of field lines.			-	
765 Maintenance of field compressor station equipment.			-	
766 Maintenance of field measuring and regulating station equipment.			-	
767 Maintenance of purification equipment.			-	
768 Maintenance of drilling and cleaning equipment.			-	
769 Maintenance of other equipment			-	
B.2. Products Extraction				
Operation				
770 Operation supervision and engineering.			-	
771 Operation labor.			-	
772 Gas shrinkage.			-	
773 Fuel.			-	
774 Power.			-	
775 Materials.			-	
776 Operation supplies and expenses.			-	
777 Gas processed by others.			-	
778 Royalties on products extracted.			-	
779 Marketing expenses.			-	
780 Products purchased for resale.			-	
781 Variation in products inventory.			-	
782 Extracted products used by the utility - Credit.			-	
783 Rents.			-	
Maintenance				
784 Maintenance supervision and engineering.			-	
785 Maintenance of structures and improvements.			-	
786 Maintenance of extraction and refining equipment.			-	
787 Maintenance of pipe lines.			-	
788 Maintenance of extracted products storage equipment.			-	
789 Maintenance of compressor equipment.			-	
790 Maintenance of gas measuring and regulating equipment.			-	
791 Maintenance of other equipment.			-	
c. exploration and development expenses				
Operation				
795 Delay rentals.			-	
796 Nonproductive well drilling.			-	
797 Abandoned leases.			-	
798 Other exploration.			-	
d. other gas supply expenses				
Operation				
800 Natural gas well head purchases.			-	
800.1 Natural gas well head purchases, intracompany transfers.			-	
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.	139,769,802	164,239,532	177,359,949	221,421,972
804.1 Liquefied natural gas purchases.			-	
805 Other gas purchases.			-	
805.1 Purchased gas cost adjustments.	(5,106,494)	(18,917,115)	(37,057,421)	(63,979,796)
806 Exchange gas.			-	
807 Purchased gas expenses.			-	
808.1 Gas withdrawn from storage - Debt.	4,676,111	3,334,459	4,132,771	7,301,670
808.2 Gas delivered to storage - Credit.	(4,183,655)	(4,476,230)	(4,963,076)	(8,003,476)
809.1 Withdrawals of liquefied natural gas held for processing - Debt.			-	
809.2 Deliveries of natural gas for processing - Credit.			-	
810 Gas used for compressor station fuel - Credit.			-	
811 Gas used for products extraction - Credit.			-	
812 Gas used for other utility operations - Credit.	(38,254)	(65,869)	(59,074)	(85,398)
813 Other gas supply expenses.	689,576	395,472	329,878	431,005
2. Natural Gas Storage, Terminaling and Processing Expenses				
a. underground storage expenses				
814 Operation supervision and engineering.			-	
815 Maps and records.			-	
816 Wells expenses.			-	
817 Lines expenses.			-	
818 Compressor station expenses.			-	
819 Compressor station fuel and power.			-	
820 Measuring and regulating station expenses.			-	
821 Purification expenses.			-	
822 Exploration and development.			-	
823 Gas losses.			-	
824 Other expenses.			-	
825 Storage well royalties.			-	
826 Rents.			-	
Maintenance				
830 Maintenance supervision and engineering.			-	
831 Maintenance of structures and improvements.			-	
832 Maintenance of reservoirs and wells.			-	
833 Maintenance of lines.			-	
834 Maintenance of compressor station equipment.			-	
835 Maintenance of measuring and regulating station equipment.			-	
836 Maintenance of purification equipment.			-	
837 Maintenance of other equipment.			-	
b. other storage expenses				
Operation				
840 Operation supervision and engineering.			-	
841 Operation labor and expenses.			-	
842 Rents.			-	
842.1 Fuel.			-	
842.2 Power.			-	
842.3 Gas losses.			-	
Maintenance				
843.1 Maintenance supervision and engineering.			-	
843.2 Maintenance of structures and improvements.			-	
843.3 Maintenance of gas holders.			-	
843.4 Maintenance of purification equipment.			-	
843.5 Maintenance of liquefaction equipment.			-	
843.6 Maintenance of vaporizing equipment.			-	
843.7 Maintenance of compressor equipment.			-	
843.8 Maintenance of measuring and regulating equipment.			-	
843.9 Maintenance of other equipment.			-	
c. liquefied natural gas terminaling and processing expenses				
Operation				
844.1 Operation supervision and engineering.			-	
844.2 LNG processing terminal labor and expenses.			-	
844.3 Liquefaction processing labor and expenses.			-	
844.4 LNG transportation labor and expenses.			-	
844.5 Measuring and regulating labor and expenses.			-	
844.6 Compressor station labor and expenses.			-	
844.7 Communication system expenses.			-	
844.8 System control and load dispatching.			-	
845.1 Fuel.			-	
845.2 Power.			-	
845.3 Rents.			-	
845.4 Demurrage charges.			-	
845.5 Wharfage receipts - credit.			-	
845.6 Processing liquefied or vaporized gas by others.			-	
846.1 Gas losses.			-	
846.2 Other expenses.			-	
Maintenance				
847.1 Maintenance supervision and engineering.			-	
847.2 Maintenance of structures and improvements.			-	
847.3 Maintenance of LNG processing terminal equipment.			-	
847.4 Maintenance of LNG transportation equipment.			-	
847.5 Maintenance of measuring and regulating equipment.			-	
847.6 Maintenance of compressor station equipment.			-	
847.7 Maintenance of communication equipment.			-	
847.8 Maintenance of other equipment.			-	
3. Transmission Expenses				
Operation				
850 Operation supervision and engineering.			-	
851 System control and load dispatching.			-	
852 Communication system expenses.			-	
853 Compressor station labor and expenses.			-	
854 Gas for compressor station fuel.			-	
855 Other fuel and power for compressor stations.			-	
856 Mains expenses.			-	
857 Measuring and regulating station expenses.			-	
858 Transmission and compression of gas by others.			-	
859 Other expenses.			-	
860 Rents.			-	
Maintenance				
861 Maintenance supervision and engineering.			-	
862 Maintenance of structures and improvements.			-	
863 Maintenance of mains.			-	
864 Maintenance of compressor station equipment.			-	
865 Maintenance of measuring and regulating station equipment.			-	
866 Maintenance of communication equipment.			-	
867 Maintenance of other equipment.			-	
4. Distribution Expenses				
Operation				
870 Operation supervision and engineering.	1,951,637	2,659,197	3,119,233	2,922,135
871 Distribution load dispatching.	632,872	455,915	378,468	397,129
872 Compressor station labor and expenses.	111,564	97,924	70,484	37,041
873 Compressor station fuel and power (Major only).			-	-
874 Mains and services expenses.	4,625,388	4,812,466	5,290,540	5,473,338
875 Measuring and regulating station expenses - General.	794,942	747,176	644,834	571,593
876 Measuring and regulating station expenses - Industrial.	174,094	184,867	201,756	157,467
877 Measuring and regulating station expenses - City gate check stations.			-	-
878 Meter and house regulator expenses.	1,875,765	1,696,009	1,297,445	1,310,032
879 Customer installations expenses.	1,492,616	1,418,415	1,004,698	895,735
880 Other expenses.	4,549,422	5,400,145	6,062,842	6,924,705
881 Rents.	182,434	160,999	149,387	131,335
Maintenance				
885 Maintenance supervision and engineering.	236,971	610,964	1,207,024	1,342,630
886 Maintenance of structures and improvements.	16,070	2,579	21,819	1,106
887 Maintenance of mains.	1,726,516	2,384,129	1,850,162	1,936,835
888 Maintenance of compressor station equipment.	44,493	48,661	56,633	73,765
889 Maintenance of measuring and regulating station equipment - General.	357,344	410,831	539,529	457,161
890 Maintenance of measuring and regulating station equipment - Industrial.	32,497	28,554	47,779	65,334
891 Maintenance of measuring and regulating station equipment - City gate check stations.			-	-
892 Maintenance of services.	1,553,005	2,042,415	1,774,738	1,627,916
893 Maintenance of meters and house regulators.	1,511,787	1,497,441	1,266,814	1,244,278
894 Maintenance of other equipment.	207,018	564,637	1,203,286	1,496,435
900-949 Customer Accounts, Customer Service and Informational, Sales and General and Administrative Expenses.				
5. Customer Accounts Expenses				
Operation				
901 Supervision.	(3,325)	49,195	141,146	145,763
902 Meter reading expenses.	711,524	732,825	796,415	795,972
903 Customer records and collection expenses.	6,634,133	6,091,369	5,489,472	5,478,654
904 Uncollectible accounts.	985,349	1,228,412	866,122	1,209,258
905 Miscellaneous customer accounts expenses.	1,058	832	7	131,810
6. Customer Service and Informational Expenses				
Operation				
907 Supervision.			-	-
908 Customer assistance expenses.	880,645	391,844	4,222,388	7,080,082
909 Informational and instructional advertising expenses.	49,989	31,081	30,583	180,176
910 Miscellaneous customer service and informational expenses.	-	68,587	342,654	359,135
7. Sales Expenses				
Operation				
911 Supervision.			-	-
912 Demonstrating and selling expenses.			-	4,232
913 Advertising expenses.	6,975	4,176	2,839	3,250
914 [Reserved]			-	-
915 [Reserved]			-	-
916 Miscellaneous sales expenses.			-	-
8. Administrative and General Expenses				
Operation				
920 Administrative and general salaries.	7,532,035	8,374,821	7,483,551	8,804,332
921 Office supplies and expenses.	3,273,649	3,988,348	4,162,213	4,523,492
922 Administrative expenses transferred - Credit.	(382,790)	(368,869)	(357,025)	(415,349)
923 Outside services employed.	1,564,701	1,444,583	1,591,557	783,986
924 Property insurance.	80,228	72,012	81,986	110,370
925 Injuries and damages.	1,492,958	1,357,367	1,572,433	1,661,441
926 Employee pensions and benefits.	6,031,552	6,475,079	5,779,296	6,951,421
927 Franchise requirements.			-	-
928 Regulatory commission expenses.			-	214,339
929 Duplicate charges - Credit.			-	-
930.1 General advertising expenses.	63,766	39,829	30,629	35,333
930.2 Miscellaneous general expenses.	1,039,042	857,520	1,171,419	1,032,639
931 Rents.	1,661,945	1,408,634	1,569,366	1,445,125
Maintenance				
932 Maintenance of general plant.	43,941	54,984	37,360	57,274
			0	-